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HYDROCARBON PROCESSING®

Cover Image: A view of BASF's 90,000-tpy acetylene plant at the company's Ludwigshafen Verbund site. Around 20 plants at the Ludwigshafen site use acetylene as a chemical building block and starting material for manufacturing many everyday products, including pharmaceuticals, plastics, solvents, electronic chemicals and highly elastic textile fibers. Photo courtesy of BASF.

99TH ANNIVERSARY |1922–2021|

HP Industry Perspectives

Top Projects 2021: Voting is still open

As detailed in the Editorial Comment of the October issue of *Hydrocarbon Processing*, the nominees for the 2021 Top Projects Awards have been announced, with voting ongoing at HydrocarbonProcessing.com.

Using Gulf Energy Information's Global Energy Infrastructure database, the editors of *Hydrocarbon Processing* selected 11 nominees in the refining and petrochemicals industries that are anticipated to significantly impact the global or regional downstream processing industries.

These capital investments have significantly contributed to the expansion of the hydrocarbon processing industry and have been instrumental in providing new refined and petrochemical products to traditional and emerging markets.

This year's nominees represent more than $76 B in capital investments. The refining projects (**TABLE 1**) represent more than 2.1 MMbpd of additional refining capacity at a total cost of more than $39 B. These projects—located in Africa, Asia, the Middle East and the U.S.—will provide additional refined fuels to satisfy domestic demand, increase crude processing flexibility, upgrade fuel quality, produce renewable fuels, etc.

This year's petrochemicals projects (**TABLE 2**) eclipse $37 B in capital investments and represent a significant amount of new petrochemicals production capacity: more than 5 MMtpy of ethylene capacity, 9.5 MMtpy of ethylene derivatives capacity and nearly 8 MMtpy of aromatics capacity. These projects are in four different regions: Asia, Canada, the Commonwealth of Independent States and the U.S.

The choice is up to you! Voting is still open at HydrocarbonProcessing.com. Make your selection of the projects you believe should receive this distinguished award. The winners will be revealed in *Hydrocarbon Processing's* December issue. HP

TABLE 1. Top refining project nominees

Project	Location
BAPCO Modernization Program	Bahrain
Dangote oil refinery and petrochemicals integrated complex	Nigeria
Duqm integrated complex	Oman
Lianyungang refinery and petrochemicals integrated complex	China
Norco renewable diesel plant expansion	U.S.

TABLE 2. Top petrochemical project nominees

Project	Location
Bayport Polymer's Ethane cracker and Bay 3 project	U.S.
Gulf Coast Growth Ventures' Ethane cracking and derivatives project	U.S.
Heartland Petrochemicals project	Canada
Jieyang refinery and petrochemicals integrated complex	China
Atyrau integrated gas-to-chemicals complex	Kazakhstan
Zhoushan Island integrated complex	China

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Because *Hydrocarbon Processing* is edited specifically to be of greatest value to people working in this specialized business, subscriptions are restricted to those engaged in the hydrocarbon processing industry, or service and supply company personnel connected thereto.

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In pursuit of operational excellence: A thank you from *Hydrocarbon Processing*

In late September, *Hydrocarbon Processing* hosted the International Refining and Petrochemical Conference (IRPC). IRPC Operations highlighted the latest equipment, services, tools and technologies that are at the forefront of optimizing refining and petrochemical operations and maintenance efforts for a safer, more efficient, more profitable and sustainable work environment.

The global, virtual event was viewed by more than 1,000 registrants from nearly 65 countries around the world. Nearly 70% of the event's presentations were led by owner-operator organizations from nearly 20 countries, each providing their knowledge on best practices and operational know-how.

The agenda. Prior to the start of IRPC Operations' technical tracks, a one-day Innovation Showcase was held by Axens. The half-day seminar highlighted trends and several technologies that are shaping the hydrocarbon processing industries. These topics included the changes that are transpiring within the processing industries, such as deep company reorganizations, the restoration of refining margins as crude oil prices increase and how refiners are investing in adding value to their operations to improve competitiveness. These investments include increasing renewables and biofuels production, new plastics recycling technologies and capacity, and incorporating petrochemicals production capacity into existing assets.

The remainder of the Innovation Showcase highlighted other processing technologies, catalysts and digital platforms that are optimizing refining and petrochemical operations. These topics segued into the two-day technical agenda led by informative keynotes on carbon capture and storage, the future of petrochemicals and optimizing plant maintenance in the era of digital transformation. These keynotes were followed by a deep dive into various topics to optimize operations and maintenance, including:

- Alternative fuels, biofuels and clean fuels production
- Catalysts
- Digital transformation
- Emerging technologies
- Engineering and construction
- Environment and safety
- Green petrochemicals
- Maintenance and reliability
- Process controls, instrumentation and automation
- Process optimization
- Refining and petrochemical integration
- Valves, pumps and turbomachinery
- Water management.

IRPC Operations can be viewed on-demand by visiting www.IRPC-Operations.com.

A sincere thank you to all participants. *Hydrocarbon Processing* extends a heartfelt thank you to all presenters for their time and effort in sharing their knowledge and experience. The technologies, best practices, maintenance know-how and operational efficiencies were on full display to inform and present a call-to-action for a safer, more profitable and more efficient working environment. The knowledge presented through case studies, videos and anecdotes displayed how the industry's technologies and workflows are operated in real-world scenarios. What better way to learn than through real-world experiences?

Hydrocarbon Processing would also like to thank the sponsors of the event: Axens, Babcock & Wilcox and Beyond Limits. And, as always, we want to thank our hydrocarbon processing community for their continued support.

The ability to share knowledge and best practices from colleagues around the world is a testament to the desire of industry personnel to pursue operational excellence. HP

INSIDE THIS ISSUE

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Battle of the biofuels: Renewable diesel vs. biodiesel

Fuel standards programs, such as the U.S. Renewable Fuels Standard (RFS-2) and California's Low-Carbon Fuels Standard (LCFS), have incentivized fuel producers to innovate and create new renewable fuels like biodiesel and renewable diesel. As new low-carbon diesel fuels and blends become more readily available, it is important to understand the differences between them and how each impacts engine performance.

Diesel engine basics. Before jumping into the different fuel options available, the following provides the basics of a diesel engine and how it differs from gasoline engines. In the U.S., diesel engines are commonly used by trains, boats, barges, heavy-duty trucks, public buses, and farming, construction and military equipment.

Diesel engines are compression ignition, meaning they use compression to create enough heat and pressure that the injected fuel spontaneously combusts. In most modern diesel engines, this is accomplished by using a turbocharger to compress the air going into the cylinder, directly injecting fuel just before the piston reaches its peak (top-dead-center) and relying on compression to trigger combustion.

Meanwhile, gasoline engines are spark ignition that use spark plugs to ignite a compressed mixture of air and fuel in the cylinder. The order and timing of when each spark plug receives a pulse of electricity is primarily dependent on the rotation of the crankshaft, which connects the pistons of all the engine's cylinders, and the camshaft, which controls the intake and exhaust valves.[1]

Diesel engines have the highest thermal efficiency of any internal combustion engine. Typically converting around 40% of the energy stored in the fuel into useful work, diesel engines nearly double the thermal efficiency of gasoline engines, which averages around 20%. This is largely due to the higher compression ratios of diesel engines (ranging from 14:1–25:1) vs. gasoline engines (ranging from 8:1–12:1).[1]

Fuels, blends and energy. Although new low-carbon fuels and blends are continuously being created, two primary groups of renewable fuels in the diesel pool have emerged: biodiesel and renewable diesel.

Biodiesel—sometimes referred to as fatty acid methyl ester (FAME)—is typically produced by reacting vegetable oils or animal fats with methanol or ethanol in a transesterification process to create mono-alkyl esters of long-chain fatty acids. Biodiesel contains oxygen atoms, which makes it chemically distinct from regular ultra-low sulfur diesel (ULSD). Like ethanol blending limits in gasoline engines, most diesel engine manufacturers only support diesel blends up to B20, with higher blends requiring fuel system modifications.

Conversely, renewable diesel uses the same feedstocks as biodiesel; however, it undergoes hydrotreating, thermal conversion or biomass-to-liquid production processes. The result is a fungible renewable fuel chemically identical to ULSD that can be used as a drop-in replacement for all current diesel engines.

The differences between ULSD, biodiesel and renewable diesel are best illustrated in TABLE 1, but there are a few properties worth discussing. Unfortunately, neither renewable diesel nor biodiesel can match the energy density of ULSD. This value is calculated by multiplying the energy density per unit of mass and the volumetric density and unit conversions. However, the energy density is not the only important property related to the energy and volumetric densities. Biodiesel's higher volumetric density is also responsible for its higher cloud point, poorer cold flow properties and improved lubricity vs. ULSD. Conversely, renewable diesel's improved cloud point and cold flow properties can both be attributed to its lower volumetric density.

The different chemical properties of the three diesel fuel types significantly impact the resulting greenhouse gas (GHG), nitrous oxide (NO_x) and particulate matter emissions.[3] For example, FIG. 1 compares proprietary blends of biodiesel and renewable diesel offered by Renewable Energy Group (REG), a leading producer of biodiesel and renewable diesel.

Biodiesel decreases nearly every emissions category as the percentage blended in ULSD increases; however, recent studies have proven it increases NO_x emissions compared to ULSD.[3] Although both REG Ultra Clean RD B50 and RD B20 may still reduce NO_x emissions vs. ULSD, this is a result of renewable diesel's ability to reduce NO_x emissions.

Based on this information, California's Air Resource Board (CARB) announced a change within its Alternative Diesel Fu-

TABLE 1. Diesel fuel properties[2]

Properties	Petrodiesel	Biodiesel	Renewable diesel
Cetane No.	40–55	50–65	75–90
Energy density, Mj/kg	43	38	44
Density, g/ml	083–0.85	0.88	0.78
Energy content, BTU/gal	129 K	118 K	123 K
Sulfur, ppm	< 10	< 5	< 10
NO_x emissions	Baseline	+10	–10–0
Cloud point, °C	–5	20	–10
Oxidative stability	Baseline	Poor	Excellent
Cold flow properties	Baseline	Poor	Excellent
Lubricity	Baseline	Excellent	Similar

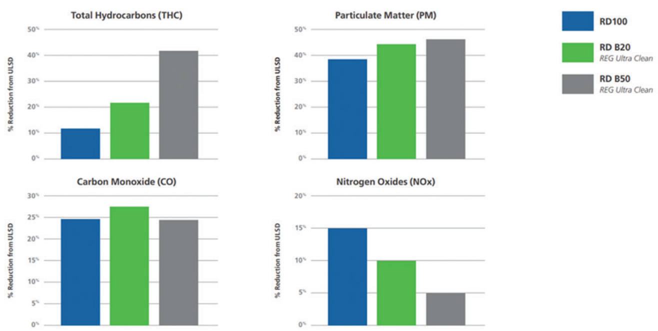

FIG. 1. Biomass-based diesel emissions reduction estimates. **Note:** REG charts are based on California's Air Resources Board assessments vs. U.S. federal ULSD. Source: REG.

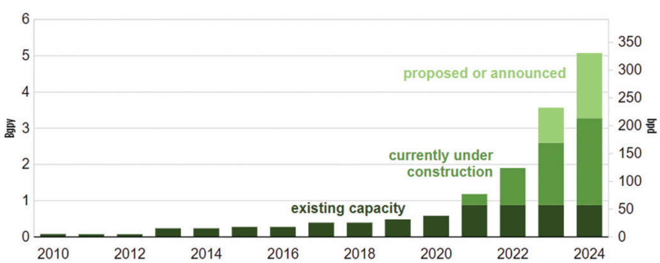

FIG. 2. Existing and expected U.S. renewable diesel production capacity, 2010–2024. Source: U.S. EIA.

els regulation, which would require biodiesel blends greater than 5% to be approved by CARB.[4] To mitigate this increase in NO_x emissions, CARB has approved diesel formulations with at least 55%–75% renewable diesel and, at most, 20% biodiesel.

Performance impacts. While most of this article has focused on the chemistry and engineering behind using these three types of diesel fuel, companies are already seeing the economic benefits of switching to renewable fuels. After dismissing the biodiesel blend B99 based on the additional fuel heater cost of $15,000/truck, Titan Freight Systems chose a renewable diesel blend of R99 to fuel its fleet.[5] After 1 MM miles, they found R99 provided the same fuel economy, while reducing lifecycle emissions by 66%, saving 1,217 t of carbon. In total, Titan Freight Systems saves about $0.021/mi—$0.015/mi from reduced exhaust replacement parts and downtime spent clearing diesel particulate filters (DPFs), $0.005/mi from a 75% oil cost reduction, and the remainder resulting from reducing the amount of DPFs required.

While saving only $0.021/mi may seem insignificant, more than 3 MM Class 8 trucks were on U.S. roads in 2019, averaging 62,571 mi, according to the U.S. Department of Energy.[6] If they had been using renewable diesel, each truck would have saved an average of $1,317.77/yr, or $5.15 B/yr in savings across all Class 8 trucks. In terms of emissions reductions, if all Class 8 trucks had used R99, it would have saved more than 297 MM metric tpy of carbon dioxide (CO_2). For context, in 2018, Florida had the third-highest CO_2 emissions in the U.S., emitting 242.5 MM metric t of CO_2, according to the U.S. Energy Information Administration.

Although renewable diesel has rapidly grown in popularity, some blenders have started to mix the two renewable fuels. For example, REG has created a blend of both biodiesel and renewable diesel (i.e., REG Ultra Clean Diesel) to capture the best attributes of each. This fuel can reduce emissions across the board, while offering improved engine starting, lubrication, reliability, engine life and more complete combustion.

Looking forward. As U.S. emissions standards continue to tighten, renewable fuels will play a crucial role in the energy transformation of the country. Utilizing the existing refining and distribution infrastructure to fuel vehicles that require little to no modification, renewable diesel and biodiesel have already overcome several hurdles associated with electric vehicles (EVs). These renewable fuels can reduce lifecycle GHG emissions even more than EVs since EVs derive their electricity from natural gas, which produces 195% higher GHG emissions on a lifecycle basis than REG B100.

U.S. federal and state governments have realized the potential benefits of biodiesel and renewable diesel and are incentivizing the production of both. A federal blenders tax credit of $1/gal of biomass-based diesel produced was renewed in late 2019,[7] and a new Congressional bill hopes to extend the program through 2025. The RFS-2 program offers 1.5 renewable identification number (RIN) credits for every gallon of biomass-based diesel produced, which includes biodiesel and renewable diesel. Renewable diesel accounts for 1.7 RINs, while biodiesel accounts for 1.5 RINs. Although RIN prices are market-based, they have recently made headlines after reaching all-time highs in June.

LCFS programs also offer credits (around $177/credit in California) based on the total tons of carbon removed compared to a baseline carbon intensity (CI). Oregon and British Columbia, Canada, have followed California's lead in enacting an LCFS, with more in development in states like Minnesota, New York and Washington.

While biodiesel and renewable diesel are both increasing in production capacity, they still have a long way to go before they can replace ULSD. In 2019, the U.S. consumed approximately 47.2 Bgal of diesel fuel. In the same year, renewable diesel and biodiesel production capacity was 0.6 Bgpy and 2.514 Bgpy, respectively. Biodiesel is clearly leading in current production capacity; however, the U.S. EIA forecasts renewable diesel production capacity to increase to 5.1 Bgpy in 2024 (**FIG. 2**).

Alternative diesel fuels like renewable diesel have proven to be a sustainable, renewable replacement for ULSD. The increased engine performance, emissions reductions and growing production capacity are all steps towards a better, cleaner future. However, with any new change comes new challenges. Partnering with experienced energy consultants removes that uncertainty throughout the transition and ensures that your organization can overcome those challenges. Understanding and capitalizing on all the available incentives is the difference between operating at a loss and becoming an industry leader. HP

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Complete literature cited available online at www.HydrocarbonProcessing.com.

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Houston: We have another problem

The state of understanding science and facts on one side and distinguishing these from anecdotes and far-fetched opinions on the other side, should be concerning to us. Institutions of higher learning can be disinclined to teach needed, applicable or actionable knowledge. While there has been talk about apprenticeship training, we have also heard selfish comments to the contrary. Fear was expressed that the trained technical person will be hired away by companies that themselves do not invest in training. As a result of this prevailing mindset, little or nothing is done.

Moreover, an overdependence on the Internet causes some to not learn how to "connect the dots" and to often miss seeing matters in their proper context.

FIG. 1. Pump manufacturers at work in Cressier, Switzerland.

In need of more lubrication knowledge. Decades ago, it became evident that lubrication issues in process industries caused disproportionate financial underperformance. Experts knew that with a little more forethought, industry could capture large benefits from reliability improvements. At that time, I approached one of the department heads at a major university and suggested that they add an undergraduate course in lubrication technology.

The department head's answer was swift. He said his university would become the laughingstock of its peers for teaching engineers how to use an oil can or grease gun to refill bearing housings and he, for one, would neither support nor even mention such a recommendation to his fellow educators. In the roughly 30 yr since floating this recommendation, I have dealt with ever more lubrication matters. I was given ample opportunities to contribute to books on lubrication technology and testify as an expert witness on lubrication-related mistakes in U.S. courts, as well as international courts of arbitration in Washington, D.C. and London, UK. I am firm in my understanding that lubrication knowledge adds much more value than meets the eye of the uninformed or indifferent observer.[1]

Consider imitating the successes of others. I have probably lived long enough to see how reluctant people in authority can be to give others an opportunity to comment on matters, before deciding on a course of action that may (or may not) be the best. While completing a 3-yr apprenticeship in 1953 and qualifying for work in a rather basic technology craft, the writer and his peers spent 20% of their working hours as apprentices in trade schools. Mandated by Germany's Federal Education Ministry, this schooling covered the relevant theories and sciences underlying their respective crafts. In 1958, the prescribed curriculum for mechanical engineering studies at the New Jersey Institute of Technology included a hands-on machine shop course.

With apologies for inserting a personal note: Between my second and third years of engineering college, I spent a few months at a BASF site that operated 55,000 process pumps. In short, there do not seem to be any downsides to simply imitating the approach taken by other successful industrial societies. Thoughtful education in both theory and practice will benefit society.

My recipe for success would be for a university (or universities) located somewhere between Brownsville, Texas and Mobile, Alabama to offer a BS degree in fluid machinery engineering. Internships would be arranged at one or more top-tier companies that repair and upgrade process pumps, dynamic and positive displacement gas compressors, and various types of turbines for customers around the world.

Companies that would make room for these internships might make it one of their priorities to point out best available equipment-related components and maintenance avoidance strategies (**FIG. 1**). These would range from amendments to API equipment standards to foundation

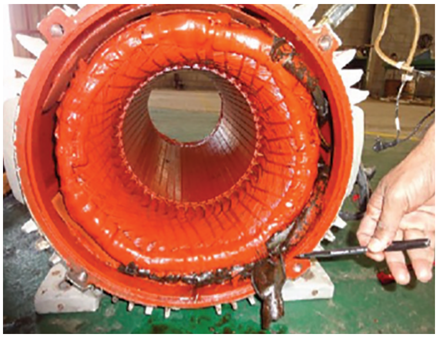

FIG. 2. Swelling standard electrical tape impeded air flow in this motor.

and piping recommendations practiced by a few best-in-class fluid machinery user companies. Interns would learn that customers not ready to authorize certain feasible upgrades on a particular repair will be hard pressed not to authorize such upgrades on one of the repair events that will likely follow.

As to the interns who receive a balanced education in both theory and practice, many of them would opt to pursue a 2.5-yr program leading to an associate degree in fluid machinery technology. All graduates would likely be hired by fluid machinery user companies that have plenty of repeat repairs or where upgrades would capture significantly improved energy efficiencies.

As to process pumps and their failure frequencies, industry desperately needs the kind of talent that feels offended when pumps made of fewer than 100 components have more failures per lifecycle than aircraft jet engines with perhaps 8,000 parts. The moral: Industry needs motivated value-adders to be productive and profitable in the years ahead.

Institutions for adult education. In the decades since 1982, some have become well acquainted with the adult learning and industry training departments of a few universities located along the Texas and Louisiana Gulf Coasts. Thirty-five years ago, short courses and lectures filled an auditorium in Beaumont, Texas. However, the last such short course (in 2018) captured a mere eight attendees in Lake Charles, Louisiana.

The need for solid training has not lessened; what has interfered, however, is the erroneous notion that everything we need to know can be downloaded from the Internet. Frankly, the Internet is largely a collection of dots or "islands of knowledge." The challenge is in *connecting* the dots, not *collecting* them. Dots, by many rational definitions, are often the equivalent of out-of-context information, and the last thing an industrial enterprise needs is anecdotal or out-of-context information.

Urgent call for motivated SMEs. Considerable evidence points to a growing problem: Since around 2000, the petrochemical industry has lost thousands of subject matter experts (SMEs) to attrition. The repercussions are foreseeable, and an actual example will make the point without much drama or tactful eloquence.

A very large petrochemical complex in the U.S. had, for many decades, used oil mist lubrication on its electric motors to great advantage. Years later, and with all the experts presumably gone, a new project was commissioned, but its many electric motors were grease-lubricated. Grease lubrication is labor-intensive, and over-greasing or over-pressuring will have a demonstrable negative effect on both bearing reliability and maintenance budgets.

The motors for the new project were probably bought from the lowest bidder. This winning bidder likely underbid others by not using the required irradiation cross-linked insulating tape for the T-leads. Irradiated cross-linked tape is needed to ensure low swelling rates. If adhesive-coated insulating tape (as used by electricians in field and shop) with its unavoidably high swell rates were being used, then the tape would become gummy and would unravel when hot (**FIG. 2**). This would impede the flow of cooling air.

Top motor suppliers recognize their responsibility as suppliers of coaxial connectors, cable assemblies, and components used within products that are targeted for contact with lubricants. Likewise, reliability-focused user companies make sound choices. Their SMEs will steer an organization toward working with responsible and trustworthy electric motor makers. The motor specifications or procurement documents developed by these SMEs would contain the words "irradiated cross-linked polymer tape" and spell out maximum allowable swell rates in numeric terms.

Manufacturers deserving of the attributes "responsible" and "trustworthy" make it their goal to fully understand the purchaser's priorities. By disclosing the range of capabilities of their products and components, the vendor/manufacturer becomes the purchaser's technology resource. Alternatively, and preferably, a reliability-focused user-purchaser will groom and nurture SMEs whose tasks include the development of rigorous motor specifications. These specifications should ensure that the motors in their plants incorporate only confirmed suitable T-lead insulation. Common sense tells us that reliability engineering includes hundreds of details akin to the ones highlighted here.

Although a common product will suffice in most applications, "standard" stretchable insulating tape will not serve well as an oil-resistant cable termination. Oil resistance can also be an important consideration in the terminal boxes of oil mist-lubricated electric motors. Common electrical tape swelling near the stator windings in an electric motor will likely impede motor cooling effectiveness. Insufficient heat removal can then drastically reduce winding life.

It has been reported that the user company described here has gone back to grease lubrication on all of its motor bearings throughout the facility, and that its pump and motor mean times between repairs (MTBR) have now fallen well below the values for which the company received much acclaim in 1984. We would recommend that they look for future degreed fluid machinery engineers or graduates of a fluid machinery technology institute which today, admittedly, exists only in our imagination. HP

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HEINZ P. BLOCH resides in Montgomery, Texas. His professional career commenced in 1962 and included long-term assignments as Exxon Chemical's Regional Machinery Specialist for the U.S. He has authored or co-written over 780 publications, among them 24 comprehensive books on practical machinery management, failure analysis, failure avoidance, compressors, steam turbines, pumps, oil mist lubrication and optimized lubrication for industry. Mr. Bloch holds BS and MS degrees (cum laude) in mechanical engineering. He is an ASME Life Fellow and was awarded lifetime registration as a professional engineer in New Jersey. He is one of 10 inaugural inductees into Newark College of Engineering's Hall of Fame, which honors its most distinguished alumni.

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Why it is time to move on from the thermowell

Thermowells are widely used in industrial applications for measuring temperature; however, with new, high-accuracy, non-invasive alternatives available, it is time to move on from thermowells and embrace more innovative measurement techniques.

Temperature is one of the most critical process parameters for ensuring the safety, quality and energy efficiency of oil and gas plants. Failure to measure it correctly can—in serious cases—lead to catastrophic equipment failure, plant destruction, endangerment to life and potentially vast losses in the event of a major incident.

For years, the thermowell has been the go-to option for measuring temperature in industrial settings. It is used to guard temperature sensors from damage caused by excessive pressure, corrosive materials and high-velocity materials, including oil, water, sand and gas, among others. However, the thermowell suffers from certain limitations compared to alternative technologies: it can fail with relative ease, leading to potentially catastrophic damage to equipment or injury to personnel.

To make matters worse, every time a thermowell fails, the operator must shut down the process until the device can be replaced. This is primarily because a thermowell must be in physical contact with the substance being measured, potentially requiring additional drilling and installation of extra safety features. If a replacement thermowell cannot be quickly and easily sourced and installed, this can potentially take weeks, incurring significant costs in lost production.

While thermowells are extremely accurate when properly installed and operated, the wrong choice of insets, incorrect insertion lengths, or poor contact can all lead to measurement errors. Without a second thermowell installed in the same location to compare and validate readings, these errors can go undetected. This, in turn, can lead to damage to related equipment both upstream and downstream (e.g., a pump running dry and overheating may not be detected until it is too late).

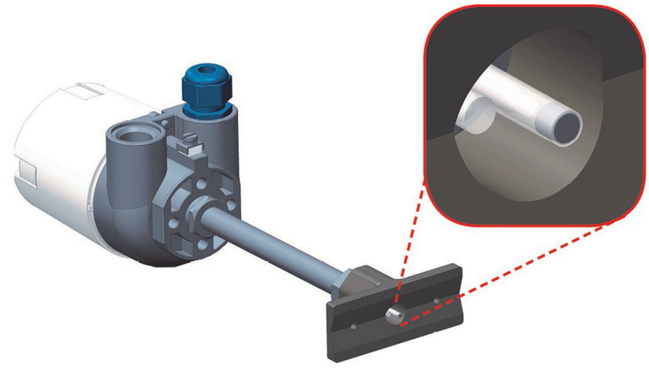

FIG. 1. Using the pipe itself as the sensor, non-invasive temperature measurement determines its surface temperature to then predict the process temperature based on process conditions.

High-precision, non-invasive temperature measurement. A new type of measurement device can provide comparable or superior performance in terms of safety, cost effectiveness, performance and simplicity, all without compromising accuracy and response time. Non-invasive temperature sensing is a simpler and safer way for plant operators to measure process temperatures, with no need for shutdowns, additional drilling or lengthy downtime between failures. It has the potential to revolutionize temperature measurement, particularly in oil and gas applications.

Non-invasive temperature measurement uses the pipe itself (**FIG. 1**) as the sensor and measures its surface temperature to then predict the process temperature based on process conditions. Crucially, no contact is needed with the medium being measured, significantly reducing the cost, complexity and time required to install and operate. It also reduces risks for humans, the environment, the process medium and other system components, while keeping downtime to a minimum. The subsequent increased plant availability from eliminating shutdowns significantly reduces system costs. Compared to a thermowell, the author's company's non-invasive temperature measurement devices can achieve more than 75% CAPEX savings.

Devices for measuring the surface temperature of piping are not new. However, traditionally they have been limited by hampered performance resulting from inadequate design, poor location or incorrect installation, all of which can lead to reduced accuracy and response times. If improperly insulated, these "skin temperature" sensors can be sensitive to ambient conditions that may affect measurement accuracy.

The company's non-invasive temperature measurement solution navigates this challenge by using a double sensor architecture combined with a software solution. One sensor is in contact with the surface of the pipe, while the second measures ambient temperature. The software measures the readings from the dual sensors and uses the resulting data to calculate and output the true process temperature in real time. By considering the ambient conditions during measurement, the transmitter significantly increases the accuracy and responsiveness of the sensor. The proprietary software includes models that predict the range of application of the sensor (i.e., liquid flowing in metal pipes) and can calculate the temperature with similar accuracy to that of a thermowell, with a similar or superior response time. The simplicity of installation, combined with the eliminated downtime, can vastly reduce the cost of temperature measurement in such processes.

Where can it be used? Because this technology is suitable for heat exchanger control and monitoring, it is applicable for every operating plant around the world. Many heat exchangers lack inlet or outlet temperature sensing, making optimization difficult. Pumps are another application that can benefit—particularly those in hazardous locations—from early detection and prevention of overheating. Highly corrosive flows, where the harsh conditions can often lead to the premature failure of thermowells, are also a good candidate for non-invasive measurement, which can also be used for validating existing temperature points. Installing two thermowells to check the veracity of an existing measurement can be risky and expensive, whereas a non-invasive solution is quicker and safer to install and operate. Its versatility makes it suitable for both new applications and retrofits.

Another benefit of non-invasive measurement is its versatility. A typical plant has tens to hundreds of different dimensions of piping, with an equivalent number of different thermowells, insets, inset lengths and material configurations. With the non-invasive approach, a single variant can be used for piping from DN40 to DN2500, and can apply to more than 70% of all measurement points. It also reduces the amount of time and cost associated with specifying and installing a thermowell, which can often take several weeks from start to finish and requires wake calculations and assessments of the device's design, size and type of material required for the process medium. A typical non-invasive solution can be installed in less than 1 hr without the need for drilling into pipelines, as the sensor is attached by clamp collars (**FIG. 2**).

Digital enabler. Non-invasive measurement is also a key enabler of the plant of the future. The addition of digitalization to a previously analogue process opens up new opportunities for the integration and application of process data across the plant.

Looking to the future, further developments in non-invasive temperature measurement, along with smarter and more specific software algorithms, will continue to help companies transform their ability to measure an expanding range of flow regimes and fluids with more complex heat transfer behavior, such as gases, without compromising accuracy, reliability and responsiveness. HP

FIG. 2. A typical non-invasive solution can be installed quickly and easily without the need for drilling into pipelines, as the sensor is attached by clamp collars.

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Digital twin for refinery production optimization

Digitalization is fundamental to Repsol's strategy for the future. To meet emerging challenges, the company has developed an ambitious program comprising of multiple projects. Within the company's industrial business, the development of a digital twin for refining processes leads the digitalization program. The digital twin maximizes production, while optimizing energy consumption.

At a virtual industry event[a], I described the project in which a digital twin has improved the accuracy and scope of the refinery linear programming (LP) model that makes decisions regarding crude feedstock purchasing and refinery unit operations.

Key objectives. Repsol devised the project to increase the accuracy and frequency of updates for their planning models to improve decision-making. A cross-functional team—consisting of personnel from KBC (a Yokogawa Company) and the author's company—developed the technology. The initial project took place at a refinery in northern Spain.

The team deployed a digital twin that combines a proprietary process simulation software[b] first principles model with a proprietary data management platform's[c] historian and dashboards. Key objectives included simplifying workflow, the planning model and model evaluation. By automating data collection and processing, the digital twin enables more focus on analyzing results rather than generating data. It also provides indicators that can be monitored briefly to check the health of LP vectors and the simulation model vs. actual process conditions.

To simplify the planning model, the digital twin can, if necessary, update the LP vectors based on the rigorous process simulation software's model. The digital twin also provides model assurance through early detection and notification of relevant deviations between actual data and LP vector results.

A single version of the truth was another key objective. The digital twin provides access not only to the process and lab data but also to derived indicators that can be used throughout the organization.

Implementing the solution. The key technologies are the proprietary process simulation software and data management platform. The process simulation software[b] is a digital twin that is based on a first principles model originally used for process simulation. Deployed in a backcasting prediction mode, it provides the calculation of critical operating parameters that allow an improved understanding and monitoring of the process. It is sensitive to changes in feeds, operating conditions, catalyst used and fractionation. It also provides updated calibration generation for the digital twin.

The process simulation software generates indicators to monitor input data quality, reality vs. model results (LP vector and simulation model) and health of the tool. If there are deviations, it also generates new LP vectors based on monitoring criteria. The model is automatically run on a regular basis, as required, typically daily or weekly. Data transfers between the simulation software and data management platform are bi-directional.

The differences between a digital twin and a traditional simulator are worthy of review. The digital twin is a replication of the actual process, and it allows for improved operation and understanding of the facility. While a simulator provides an accurate representation of a particular operating case, the digital twin is an accurate representation of the asset over its full range of operation. Rather than a snapshot in time, the

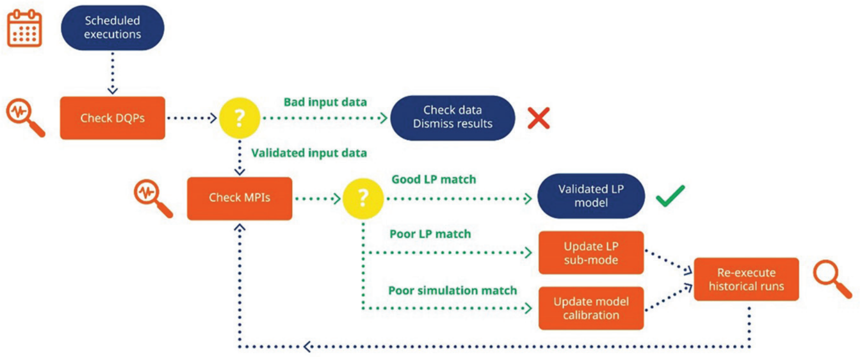

FIG. 1. Workflow calls for regularly scheduled execution of the digital twin, with validation checks on data quality parameters, key performance indicator checks, LP model validation and, if necessary, LP model updating and recalibration.

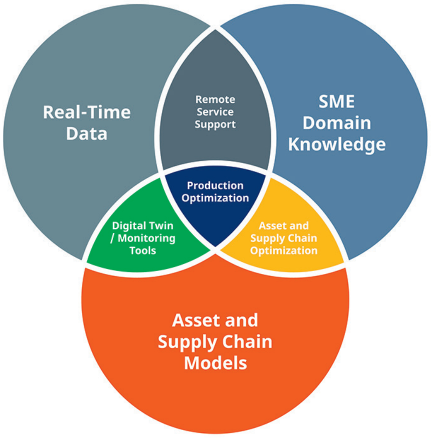

FIG. 2. The centralized solution provides information to all stakeholders throughout the organization.

digital twin captures the full history and the future of the asset.

Instead of being built on an ad-hoc basis to answer a particular question, the digital twin is automated. Its regular model runs are built-in to business workflows. As a centralized, single version of the truth, the digital twin is used by everyone. Outputs are delivered directly to the business and enable strong corporate governance. Conversely, the simulator is typically owned and used only by isolated departments or groups.

Implementation of the solution required the team to integrate the data from the historian into the model and identify missing data. To identify systematic issues, the team conducted testing based on the historical data and evaluations of failed simulation runs. That enabled the development of trapping error mechanisms to run every week and allowed the team to complete integration of the LP model and development of an LP update tool.

The proprietary visualization tool[d] provides dashboards that can incorporate results from the process simulation software, alongside other data. The displays were developed to allow users to best follow the desired workflow. The digital twin generates a great deal of information that various stakeholders could use in many ways.

By using customized displays, Repsol could ensure adherence to a consistent procedure (**FIG. 1**). Users can generate alerts to relevant deviations or data quality. Expert users can perform deeper analysis through direct interaction with the process simulation software.

Takeaway. Aside from the experience of subject matter experts, most decision-making activities related to improving plant profitability (e.g., scheduling, planning, real-time operations and retrofitting) rely on a process model. Changing from traditional simulation to a digital twin solution ensures the best decision-making over time.

The digital twin can accelerate the identification and resolution of unit issues and improve productivity. The centralized solution provides information to all stakeholders throughout the organization, with no need for advanced knowledge of the simulation model. The digital twin provides a unified template from which all teams and business units can discuss issues such as model updates and data quality. It constitutes a single source of the truth that drives the alignment of decisions and actions across the value chain. HP

NOTES

[a] Yokogawa's "Y-NOW 2020: DX Solutions for Tomorrow" event
[b] KBC's Petro-SIM
[c] OSIsoft's PI System
[d] OSIsoft's PI Vision

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Manage integrated operating limits

For safe and smooth operations of petrochemical and refining facilities, it is vital that they are continuously run within defined operating limits, ensuring high reliability of the plant and equipment and delivering per rated capacities throughout their lifecycle. However, operating limits are not cast in stone and must be constantly reviewed to derive maximum benefit with respect to production, quality and cost.

Operating limits are not a single set of limits, but are layered and vary depending on product grades and modes of operations, including startup and shutdowns. Often, undesirable events [e.g., pump seal leaks, overflow of tanks, over-pressurizing of vessels, popping of pressure safety valves (PSVs)] occur during shutdown and startup because the safe operating limits for these modes of operations were either not defined or ignored. Based on reactor performance as well as economics—depending on the aging of the catalysts—operating limits around the reactor and catalyst should be revised between turnarounds.

This article discusses the development and management of operating limits with an integrated approach between functions that include operations, engineering, technical services and quality assurance (QA).

Aspects of monitoring and control parameters, limits. Plant design documents explain the parameters to be checked and controlled. Key design documents that provide this information include process flow diagrams (PFDs), piping and instrumentation diagrams (P&IDs) and equipment data sheets. The licensor or vendor manuals or the trips and alarm schedule supply the recommended operating limits.

The required details are available in assorted documents and come from different sources, and a change in a parameter in one document may have an impact on another parameter in another document. Therefore, it is important for the operator (operating company) to combine this information into a single master data set, which should be considered as a control document. The plant manager must ensure that this master data set is always kept current and valid. The technical services, reliability and engineering groups must confirm that all relevant information is correct and maintain an audit trail of changes.

During the lifecycle of the plant, this master data set should be periodically reviewed and updated based on risk analyses, the outcome of failure investigations, regulatory changes, upgrades in engineering standards and customer requirements. Recommendations from process hazard analysis (PHA) studies [hazard and operability (HAZOP), layers of protection analysis (LOPA), etc.] and reliability studies should be considered for updating the master data. The master data must be reviewed after every turnaround and catalyst replacement. All changes must be conducted through the company's change management process.

The master data of the plant's parameters and their respective limits become especially stringent as the plant ages. Based on analysis of failures and inspection data, new parameters may be added or limits may become tighter. Certain parameters appear only for certain operating modes and may not be relevant for other modes.

The master data set should contain all relevant information needed to run the plant in a safe manner. All parameter limits must be set as wide as possible—any operation outside of its limits for a reasonably long duration can lead to degradation of the equipment, piping or the product itself. Limits are set in many cases where trade-offs exist [e.g., lower hydrogen (H_2) quench in the hydroprocessing reactor], helping increase production rates and lower costs, and impacting catalyst life and product quality. A similar example is the reflux rate in distillation columns, which affect throughput and operating costs, and improve product quality. Tightening limits on one factor may lead to giveaways or losses in other aspects.

Aspects of a master list. A typical master list should contain the following information:

1. Tag ID: Taken from a P&ID, every tag that is shown in a P&ID should be in the master list; in turn, every tag that appears in a master list should appear within the distributed control system (DCS).
2. Tag description: The unique name of the measurement point.
3. Associated equipment ID: Every measurement point or tag must be associated with some equipment or other; association may be done either based on equipment that influences the parameter most, or equipment that is mostly impacted by the process value.
4. Name of the associated equipment; the unique name of the equipment.
5. Location of measurement; the description of the location of measurement—in the field and in the panel.
6. P&ID number: The P&ID number where the tag can be found.
7. Boundary definition: Is the purpose of the tag for monitoring or control? If the purpose is control, then,
   a. Boundary types: Whether the tag influences reliability, integrity, environment, energy, production and quality. These boundaries are not

furnished by the licensor or engineering for all tags but are to be generated by the operating company itself. It is possible that a tag may fall into two or more types.

b. Boundary levels: Type of boundary levels (e.g., H, L, HH, LL), sometimes called a standard boundary and critical boundary. Based on the company's alarm philosophy, the number of boundary levels and names may change. Every tag that has a defined boundary level has an alarm configured on the DCS. This information comes from P&IDs and vendor manuals.
c. Data type: Continuous or discrete—in most cases this would be continuous, except in cases where the system data collection has a time interval that is significantly high that the data type may be considered as discrete. The quality parameter values obtained from sampling and laboratory analysis at certain intervals can be considered as discrete.
d. Alarm priority: The alarm priority P1, P2 or P3, as defined in a company's alarm philosophy document.
e. Mode of operations: Applicable mode of operation.
f. Limits: The limiting values and the units of measurement. Depending on the mode of operations and the boundary type, the actual limit values may change.
g. Transmitter range and least count: The maximum/minimum range and least count of the transmitter or measurement gauge.

Note: Data for b, d, e, f and g should come from alarm rationalization work (refer to the section below); data for item c comes from control system engineering documents; and item g comes from the maintenance management system or asset register.

It is advantageous for the operator to enrich the master data set with more relevant information, including the level of risk (e.g., high, medium, low) associated with each tag. This should be done in line with the company's risk assessment process. The licensor or equipment vendor may not provide this information, and it will have to be generated by the company itself. Another set of data that should be included are concerned with troubleshooting steps; sometimes called "operator guide," as follows:

1. Purpose: Why the measurement point is on the P&ID.
2. Cause: Why the measured value may deviate from normal allowed operating limits (several reasons exist why the deviation may occur in normal circumstances; all known causes should be listed here).
3. Consequences: The consequences if operations are continued for a prolonged duration (both the activation of the next level of barrier and the eventual consequence may be described here).
4. Actions required to normalize: This set of actions is listed in sequential order along with checkpoints. Operators should progress through these actions in given order to normalize plant operations. Different sets of actions are for different causes, so operators must first ascertain the causes before proceeding.
5. Time required to normalize: Minimum time required to complete operator actions and allow the process system to recover.
6. Time allowed in deviations: Maximum time allowed in deviation—in some cases, this is relevant for every deviation, while the cumulative time in deviations from the last outage or last inspection would be meaningful. Both the limit itself and the allowed time in deviation depend greatly on equipment metallurgy, design rating, mode of operation, sampling locations and frequency of sampling analysis, inspection locations and frequencies, the age of the plant, etc.
7. Responsibility: Person or role responsible for maintaining the measured value within the range, otherwise the same should be escalated for further troubleshooting at the subject matter expert (SME) level.
8. Owner/accountable party: The SME in the technical hierarchy who makes sure that the limits and all other information remain correct and relevant.

Note: High-quality content is a demonstration of operational excellence and the deployment of best practices. Content is updated each time an abnormal situation is encountered and the normal situation is restored.

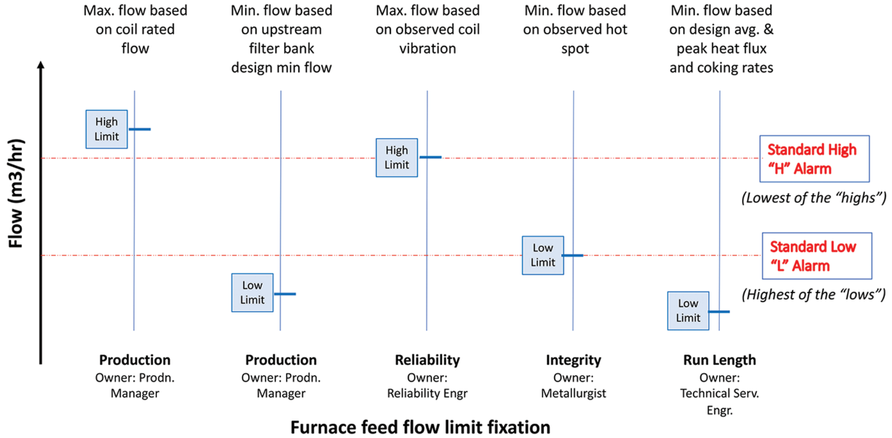

FIG. 1. A typical consideration for fixing the standard high and low limits for a furnace feed flow. Various considerations have their own minimum/maximum limits.

Alarm rationalization. Most of the required information and details should be generated by a cross-functional team in a working session called alarm rationalization (AR.) The AR exercise is highly productive if participants include experienced panel operators, engineers from operations, process engineers or technical

services engineers, control system engineers and reliability engineers.

A rigorous AR exercise proceeds through P&IDs one-by-one and systematically covers all tags. This approach is effective if the AR is carried out for the first time for a grassroots plant. For a plant that has been in operations, with adequate knowledge about plant behavior, a system-by-system approach may be taken—e.g., in a crude distillation plant, the crude column can be considered (typically approximately 50–60 tags) and rationalized, and the same can be done for the vacuum column, and so on. As a best practice, the team should yellow-line the tags that have been rationalized on the P&ID sheet so it can be verified that no tag is missed.

Rationalized limit sets may be updated into the DCS using the company's change management process. Since the changes implanted with respect to the measurement points (adding/deleting tags) or limits have an impact on the process safety aspects of the plant, the updating of the DCS with rationalized data should be done following proper communication and training of the relevant operating staff.

Two types of risks must be considered while making the change: the risks associated while implementing the change (i.e., writing new limits over the old limits, which entails human errors); and continued operation with new limits, the actual "toll" on the plant and equipment that can only be determined over time. The updating itself may be done in many ways (a system-by-system approach, updating all revised data and allowing operators to adapt to the new limits, etc.). Another approach is more global: rationalization for the entire plant is completed and its entire data set is updated simultaneously. All approaches have their own pros and cons—plants should manage the changes as per their convenience and practice.

Limit fixation. **FIG. 1** shows a typical consideration for fixing the standard high and low limits for a furnace feed flow. Various considerations (design rates, upstream and downstream system constraints, physical conditions of the coils, etc.) have their own minimum/maximum limits. During the rationalization exercise, all inputs are considered and the most favorable or logical high or low alarm limits are set.

Operating limits are not cast in stone and must be constantly reviewed to derive maximum benefit with respect to production, quality and cost. Often, undesirable events occur during shutdown and startup because the safe operating limits for these modes of operations were either not defined or ignored.

Ensuring the quality of the master data set. One way to ensure that the master data set has been improved is to compare the alarm key performance indicators (KPIs) before and after the change. One of the simplest alarm KPIs is the average alarm count, which can be 6 per hour per console. However, this only indicates the short-term effectiveness and at the operator level. To determine long-term effectiveness, close monitoring of the process performance under various product grades and modes of operations is required. An effective KPI to track this is the peak alarm count, which can be 60 per hour per console.

Another way to check if the changes have added value is to test them on an operator simulator, provided an operator simulator has been maintained with up-to-date plant information or replicates all DCS graphics.

Of course, in the medium and long term, the continuous reduction in equipment failures, loss of containment due to internal corrosion and leaks, throughput loss due to fouling, etc., are evidence of a good operating limit set.

Operating companies may set their own leading/lagging KPIs to track the effectiveness of a good limit set.

Note: Alarm KPIs should be defined in the company's alarm philosophy document; if this is unavailable, all petrochemicals and refining facilities may refer to International Society of Automation (ISA) 18.2.

Change management. As mentioned here, all changes should follow the company's change management process, which should be audited periodically, simplified and made more effective. A best practice is to carry out a complete AR of the whole plant every 5 yr or every time a major turnaround is executed.

Enforcement. Most plants maintain their master data in a standalone system and use it for reference or audits. Operating limit sets are configured directly into the DCS. When a product grade change or operating mode change happens, companies use one of the following two methods to change the alarm limits in the DCS: allow the operator to change the limit sets through an SOP on the operating panel itself or ask the control system engineer or shift supervisor to make changes from the engineering workstation/supervisory system. In these two cases, human intervention is involved. It is advisable to follow a doer/checker approach for such critical changes, although such changes happen frequently and a risk of laxity can creep in.

An advanced management practice to ensure the right limit sets are used by a shift operator is to deploy digital tools and empower the operator to enforce the right limits into the DCS, as per the product grade or operating mode. The digital tool should allow the shift panel operator to check at the beginning of each shift that all alarm set points in the DCS are consistent with the master limit set, ensuring no discrepancies. In this case, the DCS is wired with an external master alarm data set that requires the installation of stringent security architecture to prevent undesirable protocols into the DCS process control system by external sources.

Both methods discussed here have their own inherent advantages and disadvantages—the operating company should determine the best fit. HP

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The path forward for process automation: Multivariable control as core competency

In process automation, multivariable control has always been considered an area of specialization and a luxury for those companies with sufficient scale and resources to justify its high costs of ownership. However, one of the key insights to emerge from the past few decades is that multivariable control is *not* a specialization. It is, instead, a fundamental aspect of virtually every process operation—ask any operator or process engineer.

The question is not whether or not a process has multivariable control, but whether it is carried out manually (by the operating team) or automatically (by a method of automated multivariable control). Moreover, multivariable control can be more easily understood and readily mastered by observing traditional manual multivariable control principles and practices throughout industry, rather than by struggling with the conventional, highly specialized multivariable control paradigm.

In the coming two decades, the dominant process automation activity will most likely be multivariable control. Industry has already undergone several decades of multivariable control activity, but the conventional paradigm (model-based multivariable control and real-time optimization, or MPC) has never evolved into the core competency needed to meet industry's widespread scalable needs. Much work remains to be done, and more agile tools are needed to do it.[1] With traditional manual multivariable control as a guide, automated multivariable control core competency will finally emerge.

What is multivariable control? When console operators make setpoint and output adjustments to single-loop controllers in the course of process operation, that is manual multivariable control. Operators typically make multiple controller adjustments in concert, with multiple constraint limits and optimization goals in mind. This is the most practical and intuitive way to understand the role of multivariable control in process operation—the coordinated adjustment of groups of related controllers for constraint management and process optimization purposes—whether carried out manually by operators or with the aid of automated multivariable control technology.

Operators make controller adjustments based on many considerations, including their training and experience, feedback from process alarms, input from process engineers and supervision, and operating orders that typically flow down the chain of command from daily sitewide production planning and optimization (PP&O) meetings. The entire operating team works together in this way to meet production and optimization goals, while safeguarding reliable process operation. This inherent activity can be found in place on virtually every process operation in industry because the multivariable nature of most processes demands it, and because it is actually the most natural, effective, state-of-the-art way to manage and operate complex industrial processes.

In this light, *manual* multivariable control has always been a core competency of the process industries, and each site's level of success is dependent upon its ability to master it. To take process operation, automation and optimization to the next level, *automated* multivariable control must also become an industry core competency.

Model-based control and real-time optimization. Model-based control and real-time optimization are double-edged swords. While powerful in concept, they have proven to be too complex and frag-

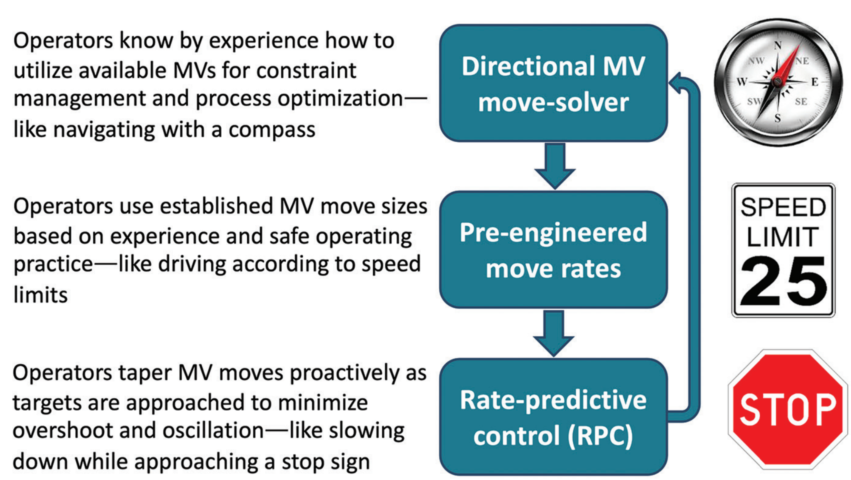

FIG. 1. The basic method operating teams have always used for manual multivariable control, which notably does not require process models or real-time optimizers. This method can be automated to provide a less fragile and more readily mastered multivariable control tool.

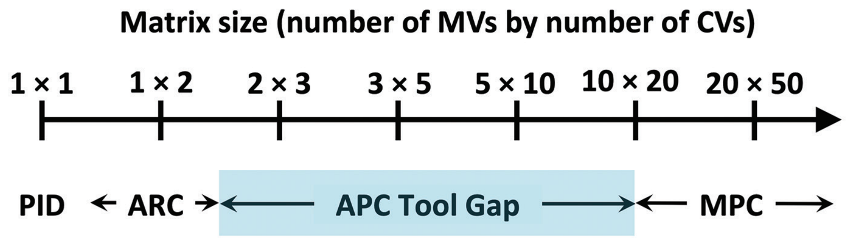

FIG. 2. The APC tool gap. Traditional advanced regulatory control (ARC) has limited capabilities, while the high ownership costs of conventional MPC make it suitable mainly for large applications. This has left a large tool gap for industry's many midsized multivariable control applications, which can be filled by more cost-effective and agile APC tools based on insights from traditional manual multivariable control practices.

ile—primarily due to the unreliability of the models upon which they depend—to evolve into low-cost, low-maintenance, high-agility, long-lifecycle technologies (i.e., into core competencies). Several articles report that more than half of MPC applications perform at pre-installation levels or have been removed within 18 mos–24 mos.[2] This combination of high cost, high maintenance and short lifecycle is increasingly considered unsustainable.

Model-based control and real-time optimization are often considered synonymous with multivariable control, but they are actually just part of the way conventional MPC solves the multivariable control problem. Other ways exist to do multivariable control that do not entail these elaborate and fragile methods. For example, **FIG. 1** outlines a method of multivariable control that basically mimics (automates) traditional manual multivariable control methods that do not depend on detailed models or embedded optimizers.

In retrospect, industry should not be surprised by the pitfalls of large-scale model-based control, because the same lesson was learned in single-loop control long ago. Feedforward is the single-loop equivalent of model-based control and is equally powerful—in concept. However, industry uses feedforward very sparingly—less than 5% of loops—due to the added cost, risk and maintenance associated with any model. MPC was expected to overcome this limitation by virtue of more careful plant step tests and better model identification tools, but instead industry discovered that models change frequently for a wide variety of reasons, so that model identification is a shifting target. Rather than solving process control tuning and performance issues once and for all, MPC took application support to vast new levels. Fortunately, experience and insights now show that multivariable control, just like single-loop control, can be readily accomplished using feedback control algorithms with or without the selective use of key feedforward models.

"Real-time" optimization, defined as optimization deployed at the control layer in conjunction with multivariable control, also may be on a declining trajectory. Aside from its part in MPC complexity and fragility, optimization at the control layer cannot begin to compare with modern optimization practices at the business PP&O layer in terms of sophistication of tools, site-wide breadth of scope, appropriate optimization time scales, etc. At the same time, modern connectivity makes it easy to share information between layers, so that multivariable control can directly utilize PP&O results, rather than be burdened with its own inferior optimizer. As a further emerging concern, the high support and maintenance of model-based control and real-time optimization put them at odds with modern control network reliability and cybersecurity principles.

Benefits and metrics.

Industry adopted the intrinsic value of closed-loop control over open-loop control decades ago, so that "loops in manual" is one of the most common process control metrics among top-tier operating sites today. Industry also adopted the idea that console operators should not be distracted by excessive numbers of low-value alarms, so that "bad actor alarms" is another nearly universal alarm management metric.

This says a lot about the number of loop interventions (i.e., the number of controller setpoint, output and mode changes) that occur daily at an operations console. High numbers indicate excessive *multivariable* loops in manual and/or bad actor *loops*. Such a "loop interven-

TABLE 1. Comparison of the conventional multivariable control paradigm (MPC) with an updated paradigm based on lessons learned and multivariable control as an industry core competency

Conventional APC 1.0 paradigm	Modern APC 2.0 paradigm
Multivariable control (APC) is a specialization and a luxury of "deep-pocket" operating companies.	Manual multivariable control is a core competency and an inherent operating team skill, observable in nearly all industrial process operations.
Multivariable control is "owned" primarily by offsite APC specialists and is often a black box to the onsite operating team.	Multivariable control is a well-understood aspect of operation and is "owned and operated" primarily by the onsite operating team.
Model-based control and real-time optimization are the only way to do multivariable control; industry is "stuck" with the conventional APC paradigm (MPC).	Other ways to do multivariable control do not use elaborate and fragile methods, as illustrated by traditional manual multivariable control operation practices.
Processes are viewed as either having or not having multivariable control.	Processes are operated with either manual or automatic multivariable control, with the same fundamental importance as single loops in manual.
Benefits must be large to justify the high costs of ownership, leading to a limited number of large-matrix applications.	The costs are low, and benefits range from intrinsic operational and economic improvements to large-scale economic ROIs.
Multivariable control has low agility, high ownership costs, fragile performance and high maintenance.	Multivariable control is a core competency with high agility, affordable costs and reliable long-term performance.
APC metrics are also complex and accessible mainly to APC specialists; simple "service factor" is misleading and has been widely discredited.	APC lends itself to effective transparent metrics, such as the loop intervention and MV utilization metrics.

tion" metric is transparent, responsive and embodies a wealth of APC measurement and management information [as a good key performance indicator (KPI) should]. For example, it measures the activity load on console operators; indicates the health of existing multivariable control applications; identifies missing/needed applications; and identifies top bad actor loops. Industry now has an "alarms per hour" guideline for effective operation; should industry also have a "loop interventions per hour" guideline? Loop interventions, not service factor, should be industry's go-to metric for APC, along with the MV utilization metric.[3]

The benefits of closed-loop (automated) multivariable control are fundamentally the same as for closed single-loop control: more consistency and timeliness, fewer alarms and constraint violations, and greater optimization. As automated multivariable control evolves into a core competency and costs of ownership decline, many applications will be justified based solely on the intrinsic value of closing the loops and improving the metric, just like traditional single-loop control practice. At the same time, more effective automation of many multivariable control applications will continue to bring the large-scale economic benefits often associated with conventional MPC (**FIG. 2**) (**TABLE 1**). HP

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Materials management: Data-centric execution to enhance organizational productivity—Part 2

In Part 1, the broad concept of materials management was discussed, along with materials management as an investment and attitude. Part 1 also provided several examples that communicate the hidden costs of poor materials management execution. Part 2 will show how data-centric execution, with object-oriented focus and exposure to a common data environment (CDE), fosters elevation out of detrimental siloed document-centric execution; how collaboration among all transactional parties via a CDE—not just engineering, procurement, construction and project controls, but also suppliers, service providers and the owner/client—can facilitate efficient project execution; and several areas where a forward-thinking materials management team can identify and drive transformational work process opportunities via an object-oriented approach to offer significant productivity enhancements.

Transition from document-centric to data-centric/object-oriented execution. Materials acquisition on capital projects has historically been a tortured process, where engineering design evolves by project facility and where materials are first quantified by the facility. Quantities then need to be morphed into supply-chain-related commodity groups, irrespective of facility and managed not by the facility but by commodity to achieve cost-effective acquisition. The procurement organization manages this acquisition by commodity, even having to sub-optimize commodity management by supplier. Since construction builds not by commodity but by facility, the management of acquired materials must morph back to a facility-based system.

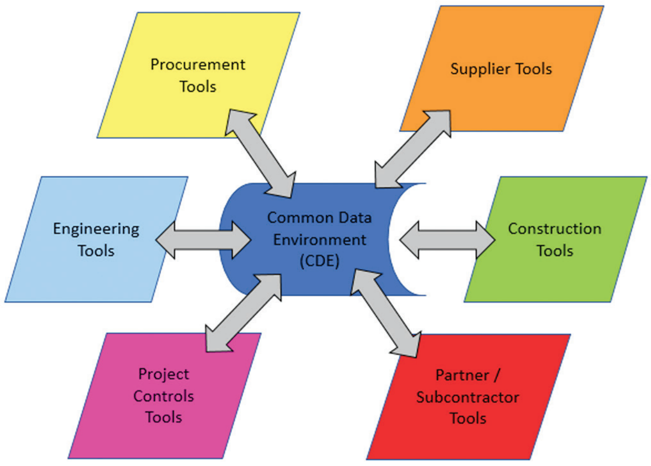


FIG. 4. Data-centric execution/CDE.

Today's document-centric execution is a throwback to the pre-computer days where procurement organizations were basically blind to upstream engineering activity until design evolved to a maturity where engineering could issue material requisitions (documents). The construction team was blind to planning construction execution until it had access to drawings (documents), purchase orders (documents), shipping notices (documents), and warehouse receipts and inventory (documents). In effect, document-centric project execution proceeded in blocks and chunks of information that were sometimes a surprise to the downstream party. In a data-centric environment, project execution proceeds in finite incrementations, with downstream parties only surprised if they are not monitoring upstream activity.

In a data-centric environment—with a CDE accessible to all parties via discipline-specific automated tools, where objects (i.e., materials) possess a fully defined set of attributes, and each attribute is owned by a subdiscipline—all parties have access to the latest status of each object. Where the CDE is attached to a building information model (BIM), all users can visualize the object via a model viewer (giving perspective to the relative importance of the object) and understand the relationship of that object to other objects (FIG. 4).

The key element in this data-centric environment that removes the informational blinders fundamental to a document-centric environment is the data maturity attribute. In a data-centric, object-oriented environment, objects (e.g., valves, instruments, vessels and pumps) are the pivot point, as opposed to being a component of a document in a document-centric environment. All objects are assigned attributes relative to their nature, inclusive of design, scheduling, acquisition and installation, with discipline-specific data maturity attributes being pivotal (FIG. 5).

How does this impact project execution? Procurement organizations no longer need to wait for a material requisition (MR) document from the engineering team. All technical aspects of an object requiring acquisition are defined by object attributes, inclusive of a design maturity attribute that allows the procurement team to harvest the information from the CDE when engineering advances the object's design maturity attribute to a milestone where the engineering and procurement

organizations have agreed to make it acquisition ready. The upstream benefit to this is that the engineering team is freed from the cumbersome process of issuing and maintaining MRs.

The construction organization no longer needs to wait for drawings (documents) to start planning and executing work. They can watch the design evolve from the model viewer, attached to the CDE and objects with attributes. This enables the construction team to passively watch the design evolve and intercede in a timely manner, as opposed to being surprised upon receipt of issued-for-construction (IFC) drawings (documents). The construction team can also query acquisition status from procurement-owned attributes of an object, again from the model viewer, as opposed to a document-centric execution where they must query either a procurement team member or, at best, access a procurement automation tool.

Where the engineering, procurement and construction (EPC) organization has collaborated with suppliers and contractors to deliver an integrated model, EPC team members can access the supplier/contractor information from the CDE or model viewer, thus streamlining information access.

Data-centric collaboration of all materials-transactional parties/model integration. Timely and thoughtful collaboration between an EPC contractor and third parties—such as suppliers, subcontractors and JV companies—has always been a key element to success. However, having to collaborate via documents has limited the collaborative effectiveness. With a transition to a data-centric, object-oriented execution, the prospect of communicating via data (not through documents such as drawings) and model integration (with a data maturity attribute assigned to each object to allow parties to share information as it evolves) opens a huge communication channel.

In effect, each collaborator can share information in a preliminary state without the data owner being committed to that preliminary information. Downstream parties would gain insight that would not have been available if they had to wait for a document. Any reliance of that upstream preliminary data will be at the peril of the downstream party if the data maturity attribute of the upstream object is not at a level that communicates commitment. Following are several examples that demonstrate this. Of course, collaborative model integration between contractual parties will not happen overnight. It will be a process that will evolve as technology facilitates it and as the value of more intelligence in a BIM matures.

Using CDE and BIM to eliminate supplier document reviews. Information about each item of materials impacts design and construction, along with project startup, whether it is a simple item like a valve or a complex item like a compressor. In the document-centric execution environment, project execution entailed a document review process where suppliers would issue and deliver drawings, specification information and manuals to the EPC contractor for review and acceptance.

For complex materials (e.g., compressors, pressure vessels and transformers), detailed design generally was an iterative process with multiple submittals before the supplier design was approved and accepted. Not only was the design evolution impacted while the design team awaited formal submittals, but the review process also required a bureaucracy simply to facilitate a submittal process that required recording of the document receipt, routing through impacted discipline teams and documentation of comments.

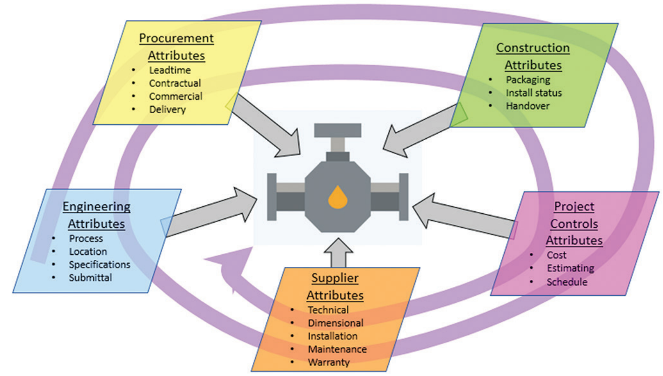


FIG. 5. The data life of an object.

A data-centric environment—where collaborative relationships (such as the EPC contractor/supplier or JV partners) engage in a model integration process, with routine (e.g., once per week) data transfers for complex equipment—not only streamlines information flow but also allows the downstream parties to view the design as it evolves, offering timely preliminary feedback for an immature design and formal comments for a mature design. Additionally, it eliminates the document review bureaucracy that is required by the process.

While the primary benefit to the EPC contractor will be in upstream engineering activities, significant ancillary benefits will flow. These include a quicker review turnaround to facilitate a shorter schedule, along with benefits to procurement expediting and supplier quality surveillance efforts.

Elimination of the concept of a materials requisition. The concept of an MR is the epitome of a process required in document-centric execution. An MR is the culmination of engineering teams capturing mature design information and quantifying that information into the documents' communicating scope (commodity and quantities), as well as technical and submittal requirements for that scope. This process is a throwback to the days when only the engineering team knew when the design was matured to a level that would allow the EPC contractor to initiate acquisition. For these MRs, EPC organizations have had to employ teams of skilled technical resources to articulate technical materials and submittal data, manage design maturity of commodity scope to quantify and time MRs to support the project schedule, and produce and manage these MR documents. All too often, MRs were not timely, as they were suffering from a silo mentality to optimize the processes involved in MR preparation or because the engineering resources and tools did not have the functionality to capture needed dates of individual items.

A data-centric environment offers EPC contractors the ability to eliminate the concept of an MR through the communication of object design maturity in the CDE. The veil of individual materials (object) acquisition readiness is removed, freeing the engineering team of the responsibility in a document-centric environment to communicate acquisition readiness. Engineering teams will still need to articulate technical and submittal re-

quirements but will do so at an object level via object attributes.

Procurement teams, facilitated by a materials management tool that can harvest objects from the CDE to capture timeliness (object required date attribute data and object lead-time attribute data), commodity (object commodity group attribute data, object technical attribute data and object submittal attribute data) and quantity (object design maturity attribute data) will be able to create proposal requests driven by schedule and commercial aspects. Benefits of an MR-free execution include:

- Engineering
  - Elimination of the bureaucracies required to quantify MR scope, to time MRs to support the schedule, and to create and manage MRs
  - Clarity to focus design to support the acquisition schedule from the CDE communication
- Procurement
  - Better acquisition planning from CDE-harvested information
  - Ability to communicate and quantify risk to project management when CDE-harvested information indicates required acquisition initiation of non-mature design data (balancing potential surplus vs. schedule delay)
  - When CDE-harvested information indicates float between design maturation and need: cash flow planning opportunities and better market management (delaying or accelerating relative to market temperature).

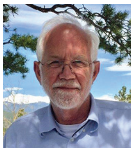
Gap elimination in the management of ship-loose materials. Most major equipment on capital projects arrives with some ship-loose items (i.e., components shipped disassembled due to issues such as logistics or warranty, requiring assembly at the jobsite). Usually, the number of ship-loose items is small, but, for complex equipment, the number can be in the thousands. Managing the delivery, storage and assembly of these items by the EPC contractor can be a challenge. EPC contractors utilize supplier vendor representatives, generally at a notable cost, to facilitate installation. When vendor representatives are to manage the ship-loose items at the jobsite, and when the EPC contractor has a robust warehousing activity, this is not a good value.

In a document-centric environment, details of granularity of ship-loose items for complex equipment are not communicated to the EPC contractor until these items are ready to ship. Often, there are multiple shipments, and the packing list data is not supplied in a data format that can be integrated into an EPC contractor's materials management system. This sparse, untimely and paper-based identification of complex equipment component data negatively impacts jobsite receiving and warehousing planning. This either forces extensive manual input of component data into the warehousing tool of the EPC materials management tool at the time of receipt or causes a process where groups of components are received by lot, with details of each lot maintained on paper. The latter causes extensive manual review of lot details whenever a withdrawal is requested. Construction planning is also significantly impacted, as construction is blind to granularity of assembly, often forcing the construction team to delay detailed planning until components arrive and an accurate state of assembly at the jobsite can be ascertained. Historically, despite grumbling by both warehouse and construction staff, these inefficiencies have been accepted as the cost of doing business, with the cost swept under the proverbial rug.

As capital project implementation transitions to data-centric execution, EPC organizations that give voice to a forward-thinking materials management effort will position themselves to capture truly transformational productivity enhancement.

In a data-centric environment (particularly one where there is a collaborative effort between the EPC contractor and major suppliers entailing a model integration process), component granularity, inclusive of attributes that articulate whether individual items will be shipped as a loose item or as an assembled piece of another ship-loose item, evolves in the CDE and model as the design evolves, thus facilitating construction planning. As the supplier's data matures by the time these components are ready to ship, data will naturally flow to processes such as supplier shipment packaging, shipment, receiving, warehousing, issuance and assembly, thereby eliminating virtually all the inefficiencies that EPC contractors face in a document-centric environment. With the inevitability of owners requesting a 6D model from EPC contractors, EPC contractors that proactively engage in collaborative model integration position themselves to support that requirement.

Takeaway. After reviewing an optimal integrated materials management approach, highlighting what can occur when a project does not engage in active materials management oversight and involvement, and discussing the ongoing transition from document-centric to data-centric execution, three areas of potential transformational work-process changes were reviewed. In discussing these three opportunities, nowhere did the label "materials management" appear; however, all three involve cross-functional coordination of materials-related work processes—the essence of materials management. EPC organizations that recognize that materials management is a function of project management, and that give voice to the opportunities presented here and the concerns raised by a lean materials management resource team, will realize the potential that optimal materials management can provide and will reap productivity enhancements, thus enabling positioning as an industry leader and profitable organization. HP



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Purchase order, contract or purchase agreement: Which is best for your procurement strategy?

Procuring equipment, materials and services are very important to a project's financial success. Extensive effort is focused on achieving quality purchases in a timely fashion at the best possible price. Most major companies procure materials and services globally. Therefore, a broad spectrum of sellers and external factors must be considered. To ensure that the supplies of products and services are consistent with what has been agreed to, purchase orders (POs), contracts and purchase agreements are widely used in the procurement process. Each of these approaches has its benefits and challenges. Sometimes a combination of these documents is used. This article describes each document type and highlights key differences and major factors influencing document selection.

The task of procuring equipment, materials and services generally represents one of the most influential responsibilities on a project regarding the team's ability to financially stay on track. Minimizing financial risk is at the heart of executing projects, so there is a large procurement focus on having safeguards in place to limit exposure. All of this creates a lot of attention on choosing the best and most comprehensive procurement documents when making project purchases.

POs, contracts and purchase agreements, both at the local site and at the global level, are the document options most often considered in executing the procurement process. Project success requires tight controls on purchases to maintain quality, budget and schedule. Using the proper procurement documents and the related processes can ensure that these goals are met. Project specifics should be considered in determining the right document for the application to avoid overkill and to also provide adequate risk protection. In the end, utilizing the right procurement document and the appropriate process will go a long way to achieve project success.

Definitions. Before discussing which document is the optimum choice for procuring goods or services, it is best to understand each. Following are definitions of each document type.

PO. This is a commercial document that usually originates, with a purchase requisition, outside of the procurement department. A person outside of the procurement department, who is often in engineering or project management, has a request for materials, equipment or services to support a project and, therefore, completes a requisition. The process is generally supported through an enterprise resource planning (ERP) platform. To adequately depict the item(s) being purchased, the requisitioner includes drawings and/or specifications and may also recommend preferred vendors. Sometimes, early in a project, a prequalification phase is conducted, and, for these projects, only "accepted" vendors are considered. The PO needs to include specifications, descriptions, quantities, prices and estimated receipt dates. The ideal PO includes payment terms and conditions, as well. Many companies have their own standard terms and conditions with clauses that cover such items as confidentiality, guarantees, termination, dispute resolution, liabilities, insurance and consequential damages. The PO can also refer to additional terms and conditions specific to equipment, materials or services, which can make it as detailed as a purchase agreement. A PO is issued before there is agreement between parties. A PO is accepted when the seller accepts the terms of procurement by signing the PO or otherwise by acknowledging acceptance in writing. Another way a PO becomes a binding contract is by the seller providing the ordered goods.

Contract. This is a legal document that details the materials, equipment or services being sold or purchased. Contracts set the agreed-upon prices, define the scope of work and detail the terms and conditions of the purchase. Details may also be displayed as addenda or exhibits at the end of the document. The terms and conditions are typically more specific in contracts than in POs. With a contract, the parties have worked out their agreement, and both parties must sign it before it is issued. A contract will typically contain all the information that would be in a PO, but this document is often longer and more detailed. These documents are often developed and reviewed by the company's lawyers or by external lawyers. Typically, a contract will contain contract sums, change order processes (i.e., changes in the work and depicting the manner in which they will be handled), payment terms, billing terms, general provisions, dispute resolutions and insurance requirements. POs become contracts once the vendor

accepts them after issuance, but not every contract is a PO. Therefore, contracts are sometimes used in conjunction with POs so that both legal and commercial aspects of the purchases are addressed.

Purchase agreement. This document is essentially a contract, and it contains the same information as previously discussed. Generally, local and global sites try to use common equipment, materials or services, which are driven by a corporate group. In real estate transactions, the terminology of a purchase agreement is used in creating a binding contract. The document used to purchase services is often called a contract or service agreement. For materials or equipment, the document is typically called a contract. As with a contract, a purchase agreement becomes binding between the buyer and seller as soon as it is signed and before issuing. This document also has a specific start and expiration date.

Key considerations. There is no simple rule that determines whether to use a PO or a contract. The choice depends on the nature of the transaction and on the relationship between the buyer and seller. The following are some important considerations.

Commodities vs. services. Commodities (e.g., steel, pipe and concrete) are well defined in terms of size, shape and materials. Prices for commodities from various suppliers can be easily compared. The purchase of these materials is routine and entails little risk. Therefore, POs with standard terms and conditions are appropriate for this type of purchase, especially if it is a one-time transaction. For repeat purchases, a blanket PO is used to expedite the transaction. A blanket PO often contains discount pricing based on volume. This kind of arrangement is good for both the buyer and seller.

Conversely, services tend to be unique and are typically site specific. The scope, complexity and duration are influenced by conditions at the site. A good example is a site maintenance agreement. Therefore, the transaction is more complex and open-ended. A contract is more useful in these situations to cover price, warranty, insurance, *force majeure,* liability and termination stated in the general terms and conditions document.

Short-term vs. long-term agreements. POs are typically used for single business transactions, although blanket POs are commonly used for repeat orders. Contracts and purchase agreements are used for the long-term agreement between the buyer and vendor. Contracts may also include renewal options. For multiple-year contracts and purchase agreements, there are generally provisions to allow for agreed price increases for future years that are generally pegged to a mutually agreed-upon benchmark or index.

Risk. Price is usually at the forefront of people's minds when making a purchase. However, equally important is the risk associated with quality and schedule. Getting a low price may not constitute success if the delivery of the product or service is delayed or if the quality is subpar. The main components of a construction contract have been described in literature.[1] The important risks are associated with an event that could not have been foreseen (such as acts of God, floods, hurricanes or fire). It may be important to include language in terms of limits of liability and liquidated damages. In these situations, a contract, which is legally binding, would likely be appropriate. To minimize risk, many contractors carry bid bonds and performance bonds, which guarantee the bid and performance of the work.

Dollar value. The absolute magnitude of the transaction needs to be considered in relation to the cost of developing a contract. For example, if the transaction for a grassroots petrochemicals plant is worth millions of dollars, it is certainly worth creating a detailed contract and developing the necessary legal paperwork by using external professional legal services or company lawyers. If the transaction is a routine purchase of office supplies that can be obtained from other suppliers in a worst-case scenario, then a PO may suffice.

Ease of use. It is a good idea to minimize paperwork and contractual documents, given the nature of the transaction. Paperwork does not add value to either party, and it is in the interest of both parties to keep it simple, while protecting their individual interests. Having a sound and robust ERP platform and an electronic document management system certainly helps.

Relationship. A PO or contract is helpful to both the buyer and seller. It defines the transaction precisely on paper, thereby removing uncertainty, reducing risks and creating a certain level of comfort. If the buyer and seller have a long-standing relationship based on mutual trust built on positive prior experiences, the paperwork can be simplified. Paperwork is needed to resolve conflict if something goes wrong. If the transaction proceeds smoothly and both parties are satisfied, the paperwork is usually redundant and sits in a file. Very rarely do conflicts get escalated to a court of law. However, it does happen when the right strategy is not adopted and followed correctly.

International vs. domestic procurement. Depending on the local costs of materials and labor, international procurement can save money. When purchases are just as likely to be made internationally as they are domestically, it is important to be extra vigilant regarding foreign purchases and logistics, as well as shipping and customs complexities (e.g., import taxes). More specific contract language is usually warranted with international purchases to keep the process on track. Therefore, a contract is preferred over a PO with standard terms and conditions.

Governing regulations vary from country to country, so it is important to explicitly spell out procurement requirements. There should even be a discussion of dispute resolution if the process reaches loggerheads. This may involve the courts in a neutral location. Extra effort is needed to understand local codes and custom duties. Time differences, along with culture and language differences, can also add complexities to the procurement process. Very often, it is desirable to use a combination of the approaches previously described.

Using a combination of approaches. There may be instances where it is prudent to use both a contract and PO(s). An example is the case where multiple purchases of different commodities and/or services will be made from a given vendor through the course of a project. A contract can be used to define overall requirements with specific terms and conditions. Then, each purchase with this vendor can be made with a simplified PO. Another reason for a contract with a PO is to highlight the importance of project requirements. For example, if a process plant or a skid unit is engineered and partially fabricated at a different location or country, and if the balance of work is required to be completed at the buyer's site, using local materials and services, then such a combination approach can be taken. Again, the devil is in the details, and the project scope must be written clearly and also understood and agreed upon by both par-

ties. This is particularly important with complex projects or in cases where delivery requirements are unique and critical.

Limitations of each approach. The limitations of each procurement document may be obvious from this article. However, to reiterate, a PO is the simplest document used in making a project purchase, but it may not be sufficiently detailed enough with respect to the contract requirements. A PO does not become a contract until it is accepted by the seller. Conversely, a contract ensures an early agreement between the buyer and seller. Additionally, contracts tend to be more comprehensive—entailing risks, schedules, scopes, etc.—and may be viewed as cumbersome for simple purchases.

Takeaway. Project procurement is generally the major factor determining whether a project stays on track financially. The lowest price is important for the buyer; however, factors such as quality and timely delivery are very critical, and all details must be holistically considered. The challenge is to select a procurement document that provides the necessary protection but that is not overly burdensome or complicated for the buyer and seller. By applying the guidelines presented here regarding the selection of a PO, contract or purchase agreement, the strong points of each document are clear and there is an understanding of any limitations. At the end of the day, procurement is not the only driver for a successful project, but it certainly is a key activity influencing project metrics. A sound strategy that is executed properly will eventually help a company develop a good vendor relationship, with a fruitful win-win partnership for both the parties. HP

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Installation of magnetic level gauges in modularization projects

In today's competitive world, new ways of more efficiently executing a project are being developed every day: one of these is modular construction. Modularized facilities allow a project to be completed more quickly, with lower capital cost and better material control. Module yards, or fabrication yards, are built at a remote location. Once construction is completed, the module is transported to the site via road or water, based on its size and destination.

In the construction of most modular units, mechanical equipment (piping, steel, cabling, instruments, etc.) are all assembled in the module to save work at the site. Therefore, it is essential that all disciplines—piping, civil, mechanical, instrument and electrical—work collaboratively from the initial design phase to the completion of engineering. Plant 3D software is used for modelling all equipment, piping, steelworks, cable trays, junction boxes and instruments with accurate dimensions to correctly assess, identify and utilize the space available.

Instrumentation has a significant amount of interface with vendors to ensure accurate dimensions. Most vendors do not submit the certified dimensions until the purchase order is placed. Modelling the instruments (especially non-standard ones) with preliminary dimensions may lead to rework at a later stage if the received certified dimensions are not inline with preliminary dimensions.

One such instrument is the magnetic level gauge, which is not a factory-standard product offered by a manufacturer and must be designed based on project requirements. Getting the certified dimensions on time is challenging; however, many factors can be addressed during early engineering stages and the bid evaluation process to save a considerable amount of rework later. This article describes the factors to be considered to finalize the correct installation of magnetic level gauges for modularized projects in the absence of certified vendor data—the research here was conducted at a large, modularized project in real time. Many factors can be missed during detailed engineering, so determining all such points beforehand and remaining aware of their significance can save time, cost and schedule.

Modular construction. In this process, a plant is divided into various modules (e.g., process, utilities, power generation) and their sub-modules, which are constructed offsite, under controlled plant conditions, using the same materials and designing to the same codes and standards as conventionally built facilities.[1]

In the authors' company's terminology, modularization is divided into three parts:

- 1st-generation modularization:
  - Prefabricated pipe racks are sent to the site
- 2nd-generation modularization:
  - 60%–70% of steel and piping are modularized
  - Pipe rack equipment are pre-installed
  - 20% of electrical and instruments are moved under the scope of the modules
- 3rd-generation modularization:
  - Process blocks are modularized
  - 95% of steel and piping are assembled in the module
  - 85% of electrical and 95% of instruments are assembled in the module
  - Most cabling, wiring and testing are done in the module yard

FIG. 1 shows a typical module assembly.

With 3rd-generation modularization, it becomes imperative for instrumentation to be designed at the right time so that accurately designed instruments reach the module yard well before the module is shipped to the site.

Benefits of modularization. Modularization has many benefits, including:

- Space: Modularized projects save space, as an optimum area is used building the large modules.
- Cost: Due to harsh weather conditions in some geographical locations, labor costs can be high. By moving the construction under favorable conditions, labor costs decrease drastically.
- Time: Due to the structured tracking and controlled environment conditions at a module yard, significant time is saved.
- Large modules are divided into small work packages to enable easy identification and precise tracking of all materials.

FIG. 1. Module assembly. Source: KOMARINE.

Magnetic level gauges. This type of level sensor is used to measure the level of fluid in a vessel or tank and includes a floatable device that can float both in high- and low-density fluid. The measuring chamber is fitted with a float with a magnet inside, which will float on the medium; the magnet in the float will turn the flaps of the indicating rail. Some manufacturers use a magnet bar, while others use a toroidal magnet on a float for the guidance.

As shown in **FIG. 2**,[2] a typical magnetic level gauge contains the following components:

- **Chamber:** The chamber is directly connected to a vessel or tank to measure the exact fluid level. Chamber configurations depend on the application and project requirements. A chamber may be side-mounted when both process connections are connected to the side of a vessel (**FIG. 2**) or top-mounted (**FIG. 3**).[3] Most projects require that the chamber be designed and tested as per Boiler and Pressure Vessel Code, ASME section VIII, Div. 1. They should also have ASME U stamping. Chambers are available in a variety of materials, depending on process fluid properties and pressure and temperature ratings. Chambers should be constructed out of non-ferrous material to avoid erroneous movement of the magnetic float, which leads to an inaccurate level indication.
- **Float:** The float is designed based on the specific gravity of the process fluid and rests on the fluid's surface (**FIG. 4**). As the float moves up or down, the magnet assembly rotates a series of bi-color magnetic flags or flaps, changing the visual indicators mounted just outside the chamber from one color to the other, as shown in **FIG. 5**.[4] The gauge pressure and temperature ratings also depend on the float. Floats are available in a variety of materials, depending on fluid properties and the capability to withstand the temperature and pressure of process fluid.
- **Indicator housing:** A visual indicator housing is clamped to the piping column in total isolation from the process liquid. It contains the choice of indicator, either a series of flags or a follower (also known as shuttle). The individual flags or the follower contain an alignment magnet that couples with the float magnets as the float moves up or down within the liquid chamber.[5] As shown in **FIG. 6,** liquid level is indicated when flags flip and the color of the flag changes. The indicator housing is directly connected to the scale, hermetically sealed, and should be made of aluminium or stainless-steel.
- **Process connection (upper and lower):** Center-to-center (c-c) length is the difference between the minimum and maximum level in the vessel to be measured. Based on the height of the fluid to be measured, multiple level gauges can be mounted on a vessel or bridle. Process connections are

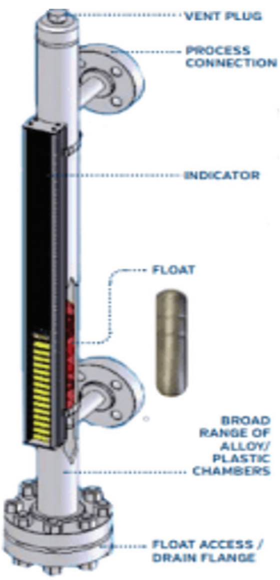

FIG. 2. Side-mounted magnetic level gauge.[2]

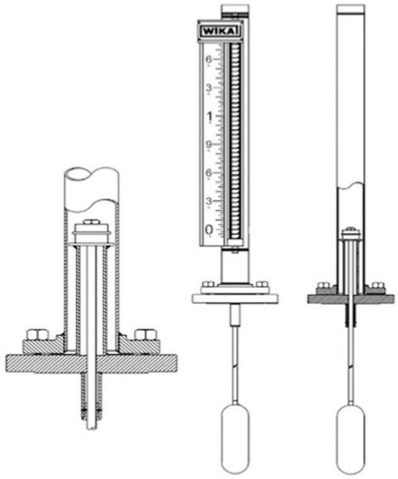

FIG. 3. Top-mounted magnetic level gauge.[3]

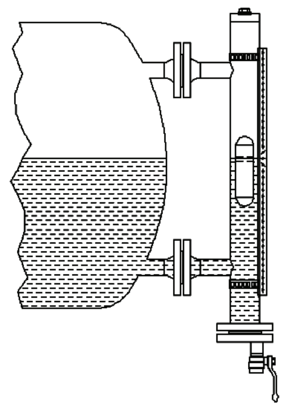

FIG. 4. The float moves up based on the level in the liquid chamber. Source: InstrumentationTools.

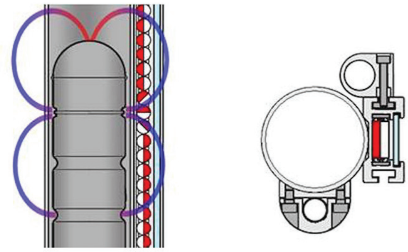

FIG. 5. Float movement affecting the movement of magnetically coupled flags.[4]

FIG. 6. Indicator housing. Source: Magnetrol.

generally flanged, and the rating of the flange should be the same as that of the vessel, or > 300 lb.

- **Drain connection:** Often during maintenance or plant shutdown, it is required to drain the unwanted liquid from the chamber. If the process fluid is hazardous or contains hydrocarbons, the level gauge chamber drain is connected to a closed drain system via piping. This connection can be screwed or flanged depending upon the project requirements; however, flanged connections are recommended for hazardous fluids.
- **Vent connection:** A vent connection is required to vent the gases that may accumulate on the top side of the chamber. To measure the correct level of the process fluid and during maintenance, draining and venting of the liquid chamber are essential.

INSTALLATION OF MAGNETIC LEVEL GAUGES IN MODULATION PROJECTS

Non-ferrous material from the centerline of magnetic level gauges. As per API 551, it is recommended that the magnetic level gauge centerline should be located at a minimum of 8 in. (20 cm) from ferrous materials (e.g., floor grating, ladders, pipes, structural supports).[6] The presence of any magnetic material in the vicinity can greatly affect indicator readings. For large vessels or columns, c-c length often exceeds 2 m–3 m. Long gauges can penetrate more than one level of grating or platforms.

On major modularization projects, modeling is an interdisciplinary effort—for example, a piping engineer models the assembly based on inputs received from an instrumentation engineer. Similarly, a civil/structural engineer designs the grating and access platforms for the instrument.

As part of the 3rd-generation modularization study, while care was taken to maintain the distance between the level gauge chamber's centerline and the face of the flange per API 551, the distance between the centerline and the grating cutout was much less than 8 in. This became a major issue, as the grating was made from carbon steel, which has good magnetic properties.

FIGS. 7 and 8 show 3D snapshots of gauge clashing the platform and beam.

Mitigation. Various solutions were proposed to mitigate this problem:

- Make a cutout of the 203-mm radius from the centerline of the chamber. This was the most cost-effective solution at the project's given stage since repurchase of new material was not required. To comply with project safety, a toe guard is required if the grating cutout is more than 25 mm, and a handrail is required if the cutout exceeds 75 mm (FIG. 9 shows a

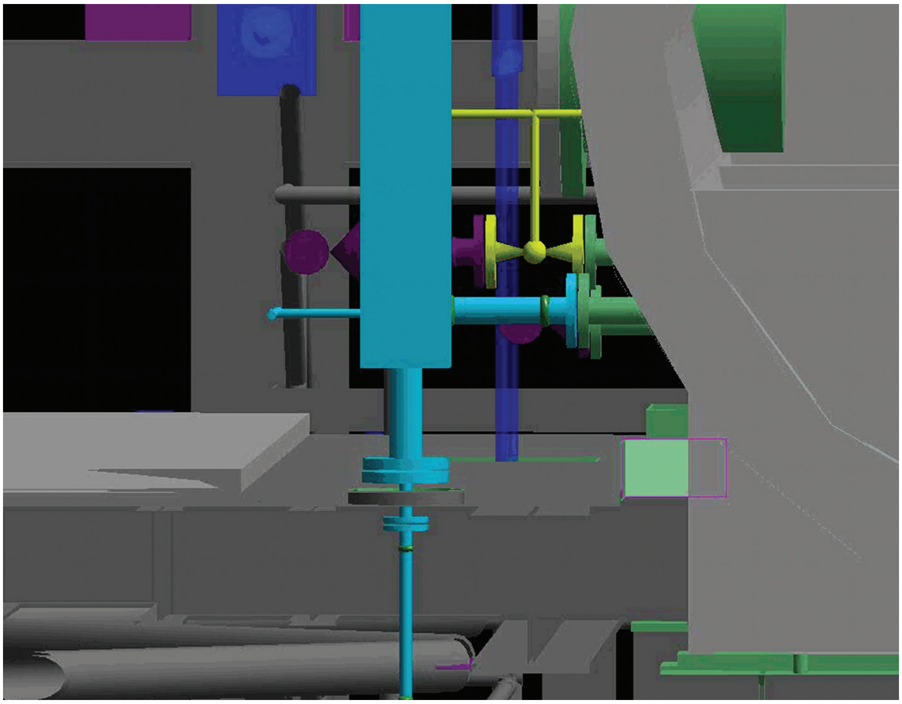

FIG. 7. Gauge penetrating through platform/grating.

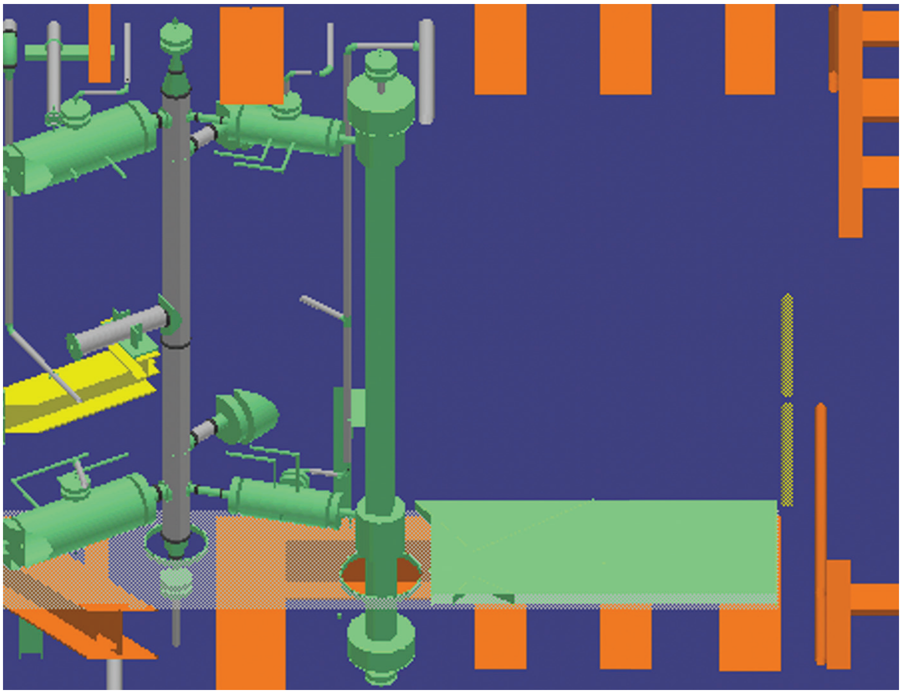

FIG. 8. Gauge bottom near steelworks.

top view of the cut-out). However, this may not be the safest solution, so it was not implemented.

- The second proposed solution was to change the grating around the level gauge from carbon steel to stainless-steel. This was the best technical solution with respect to safety and was therefore implemented. The new material was procured, and the grating was installed in the module yard on time for the module to be transported as per the project schedule.
- Moving the steelworks: Where steelworks or beams were present in the 203-mm radius of the gauge (FIG. 8), steelworks were moved further away by the civil and structural team. Even though this required more effort, it was necessary to avoid interference of ferrous material and ensure accurate level measurement.

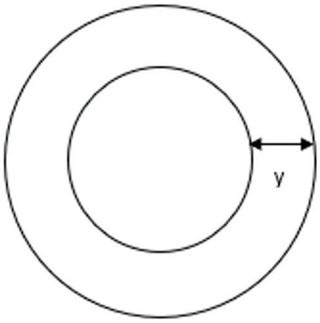

FIG. 9. Cutout in grating: for y ≥ 25 mm, a toe guard is required; for y ≥ 75 mm, a handrail is required.

Magnetic level gauge drain orientation. A drain end can be threaded or flanged based on project specifications. In most cases, if the process fluid is non-hazardous, the drain can remain open; however, it is sometimes required to route the drain to a dedicated collection tank. To facilitate this, a closed drainpipe should be installed from the level gauge chamber drain connection to the collection tank.

If a closed drain is required, this should be determined in the early stages of the design engineering phase. The routing of closed drain lines in plant design software can be completed when preliminary dimensions are received from the vendor. The certified dimensions are received only after an order has been placed—a significant increase in the dimensions of the level gauges can lead to the following scenarios, especially in 3rd-generation modularization projects:

Clearance from bottom/platform/grating. To safely remove the float during maintenance and shutdown, a minimum clearance is required from the bottom of the platform to the drain flange (generally ¾ in. or ½ in.) to remove the float without dismantling the gauge from the vessel. If the gauge dimensions received from the instrument vendor are greater than preliminary dimensions, the drain connection might have to be re-oriented. This occurred in a modularization project: the confirmed dimensions were received from the vendor after the design was fixed, necessitating a re-routing of drain piping to accommodate the increased dimensions of the level gauge, which could eventually change the isometrics of the lines that were released to the fabricator. To minimize the change and to meet the minimum clearance requirement of float removal, it was proposed to reorient the drain connection of the level gauge. Care was taken to provide the correct drain orientation (east, west, north and south) based on the orientation of drain piping. In collaboration with the vendor, the face-to-face dimension of the bottom flange to the drain flange was made as small as possible. FIG. 10 shows such a case where the drain orientation changed from the bottom to the side.

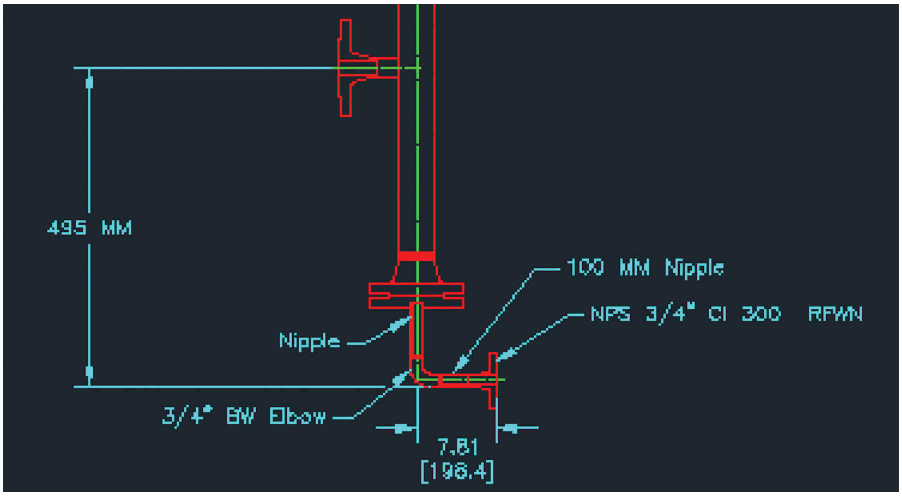

FIG. 10. Drain orientation changed from the bottom to the side.

Maintenance/access. To accommodate new increased dimensions or a change in dimensions of a magnetic level gauge, access to piping items (e.g., isolation valve) connected to the drain piping can be compromised due to space constraints. Since the goal of modularization is to save space, cost and time, these challenges are often encountered. Accurate modeling is vital to ensure access to critical and frequently used items.

Float removal. Float removal clearance is the space required to remove the float from the bottom of the platform during maintenance or float failure. Float removal clearance depends on the float length—ideally, this is equal to the float length plus 50 mm to allow easy removal from the bottom flange of the chamber. No overhead structure should be directly in line with the level gauge chamber or float removal in case of top-mounted gauges, which require a removal clearance equal to the float length plus the float guide/rod length. Any additional required clearance depends on the construction of the level gauge. Due to space constraints in modularization projects, it sometimes becomes necessary to remove the entire level gauge assembly to remove the float. This should be documented in the mechanical handling process, which describes the handling of each instrument during maintenance.

Heat tracing: Electric/steam. For applications requiring fluid to be maintained at a positive temperature and to avoid freezing, electric heat tracing, heat tape or steam tracing can be fitted on the magnetic level gauges. Trace heating is an electric heating element or steam line run in physical contact along the length of the liquid chamber.

Depending upon project specifications, electric heat tracing or steam tracing is applied to the gauge chamber; the type of heat tracing for the gauge chamber should match the vessel. All input supply must be available for any type of heat tracing (electric heat tracing, power distribution, heat tracing cables, etc.), as well as a continuous supply of steam for steam tracing.

The scope of supply for heat tracing should be defined in the project's early stages (i.e., the tracing supply should be included in the electrical/piping contractor's scope of work, rather than the instrument vendor). This helps maintain project consistency and reduces the interface between the instrument vendor, engineering team and piping contractor. The requirements should be documented in the heat tracing schedule by the instrumentation team, in heat tracing isometrics by the electrical team, and reviewed by an instrumentation engineer.

Frost-proof extensions. When tracing is not required on magnetic level gauges installed in a cold environment (i.e., when ambient temperatures are below 0°C or for cryogenic applications), it is recommended to use frost-proof extensions (**FIG. 11**) on the gauge to prevent ice from collecting on the visual indicator and decreasing visibility.[7]

Chamber support. For level gauges with a larger c-c length, the chamber requires additional support, which can be achieved with a support bracket/clip/plate installed or welded on the chamber and fitted to the support on the pipe stand, vessel or nearby structure. Generally, the vendor advises above what c-c length the chamber support is required. However, the project's piping stress team also calculates the support requirement based on the c-c length and weight of the gauge. The support bracket can be customized to align it with the support on the vessel provided by the mechanical vessel vendor. During detailed engineering, while customizing the support bracket according to project requirements, the following must be determined:

- Exact location of the support bracket
- Direction the support bracket faces

FIG. 11. Frost-proof extension. Source: Orion Instruments.

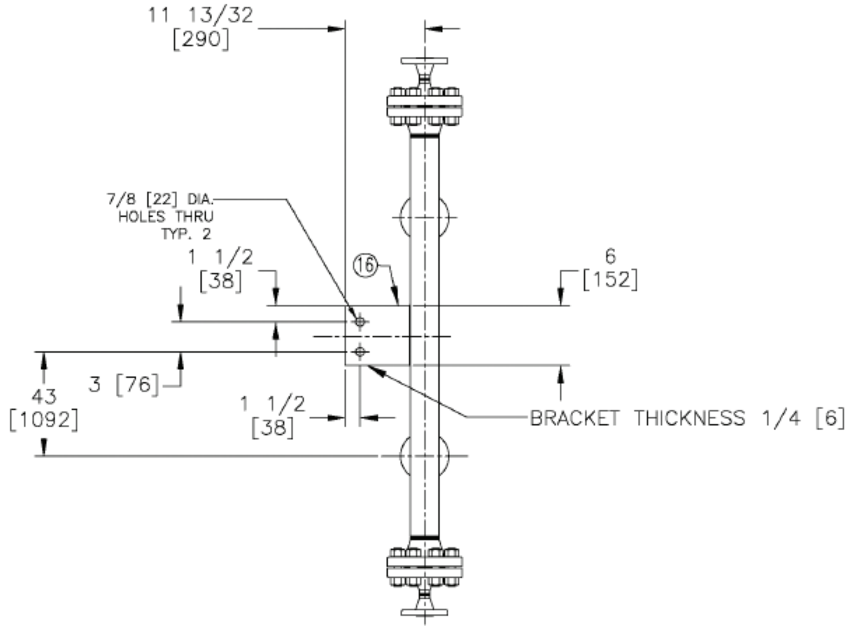

FIG. 12. Support plate welded on a gauge chamber, in mm.

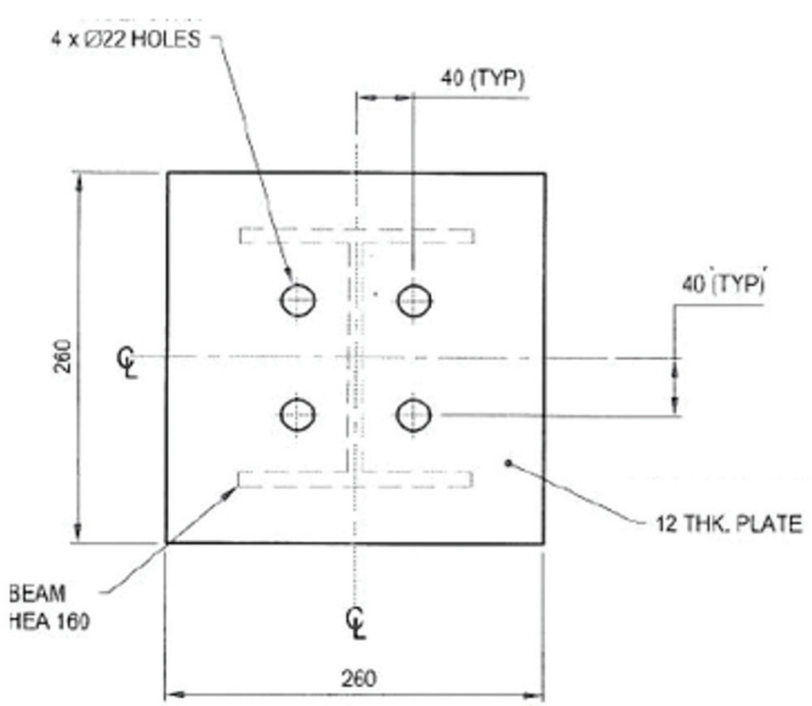

FIG. 13. An example of a support plate on a vessel, in mm.

- Thickness of the support plate; bolt holes location and size
- The centerline of the gauge chamber will remain at least 8 in. from any ferrous material to comply with API 551[6]
- Any project specifications for support plates will determine design requirements such as size, thickness, etc.

FIG. 12 shows a typical drawing of a magnetic level gauge with support plate, and **FIG. 13** shows standard support detail on a vessel that can be used as a reference in designing the support on the level gauge chamber.

Bolt holes orientation for a level gauge process connection flange. Bolt holes are placed in multiples of four, should be equally spaced, and pairs of bolt holes should straddle fitting centerlines,[8] meaning:

- For a vertical flange face (the flange face is the vertical and the line is horizontal), the bolt holes should straddle the vertical and horizontal centerlines (**FIG. 14**).[9]
- For a horizontal flange face (the flange face is horizontal, and the line is vertical above or vertical down), the bolt holes should straddle the plant north centerlines (**FIG. 15**).[9]

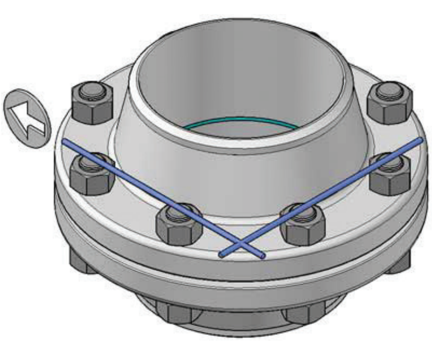

FIG. 14. Bolt holes orientation for a vertical flange.

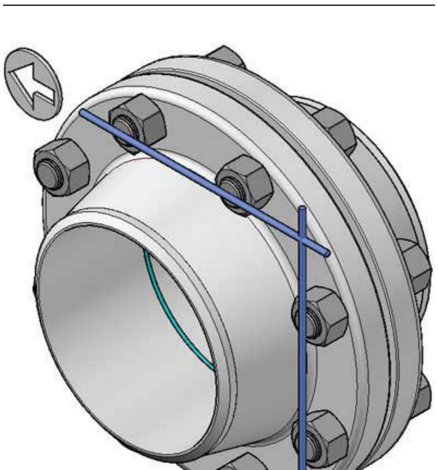

FIG. 15. Bolt holes orientation for a horizontal flange.

This "natural" centreline rule for flanges is known, understood and followed by all responsible equipment manufacturers and pipe fabricators. It is essential that the bolt holes orientation of the vessel flange and level gauge flange are the same; otherwise, the gauge will not fit to the vessel. When the mechanical vessel reached the site in a modularized project, the bolt holes of the vessel flange (for mounting the level gauge) were not straddled across the centerlines and were rotated 1° in a clockwise direction. The instrument vendor was informed of the error and asked to rotate the mating flange of the level gauge chamber connection 1° counter-clockwise so the flanges' bolt holes were aligned.

Gauges in high-pressure rating. Few manufacturers produce magnetic level gauges that can withstand a high-pressure rating of 2,500 lb and 10,000 lb. Moreover, 10,000-lb rated flanges are not covered in ASME B16.5 standards—the API 6A standard is followed for 10,000-lb rated flanges and bolts, and great care must be taken when selecting these gauges. Most of the time, the designs are proprietary, but the design must still meet the project specifications: all materials should be rated to design pressure and temperature of the level gauge; the liquid chamber should be designed as per Boiler and Pressure Vessel code, ASME Section VIII, Division 1; and all bolting and torque values, size categorization ($1\frac{13}{16}$ in. or $2\frac{9}{16}$ in.) and flange facing must also comply with API 6A.

Takeaway. Magnetic level gauges are safe and reliable instruments of level measurement and are widely used in the energy and chemicals industries. Since the size of level gauges vary (based on c-c length and float length), the best practices and methodologies of selection detailed here can aid in satisfactory installation of magnetic level gauges. Detailed modeling of a modularization project allows factors such as nearby steelworks, grating, beam supports, access, customized chamber support and float removal clearance to be determined well in advance, saving space, cost and schedules. This approach to modular construction has been adopted by many companies. With emerging technologies, the engineering and construction industry is evolving and adopting advanced techniques to execute projects in a more efficient manner. HP

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Continuous corrosion monitoring improves process optimization

Corrosion is one of the most insidious challenges in the oil refining industry. When it is uncovered too late or a slow leak has begun, it can lead to catastrophic outcomes. However, monitoring corrosion requires resources and vigilance, as well as the right analytical tools to determine when and where a problem might arise.

The issue of corrosion has become more critical in recent years as refineries opt for less expensive opportunity crudes to meet forecast production and financial margins. Many of these cheaper feedstocks tend to be more corrosive, which further solidifies the demand for a comprehensive monitoring program.

Finding the right solution to meet safety standards for assets and personnel, while maintaining budgets, requires an in-depth look at both existing tools and new options on the market. In addition, finding that midpoint between corrosion risk, process data and impact on the plant can provide a root cause analysis from which to build a suitable preventative maintenance process.

In many legacy systems, traditional methods of corrosion monitoring are used that do not necessarily provide the data to best plan production and asset maintenance. However, more and more facilities are reexamining those methods as they consider and implement more efficient and digitally accessible solutions (**FIG. 1**).

Traditional corrosion monitoring.

Although several types of instrumentation have traditionally been used in corrosion monitoring in oil refineries, two are most commonly found: intrusive corrosion [or electrical resistance (ER)] probes and manual ultrasonic inspection.

Intrusive corrosion probes consist of an intrusive element with a sacrificial tip that sits in the process fluid and is (normally) made from the same material as the surrounding equipment. As the sacrificial tip corrodes, its electrical resistivity changes, which is recorded externally; these are also increasingly available for wireless connection. The corrosion of the sacrificial tip is used to infer the level of corrosion being experienced by the surrounding equipment.

Alternatively, manual ultrasonic inspection is an equally well-established technique for measuring metal wall thickness. This technique involves placing a transducer directly onto the metal surface and generating ultrasound, which is transmitted through the metal until it is reflected off the inside metal surface (back wall). The reflected ultrasound signal is recorded, and the time difference between the sent and reflected signals provides the measurement of the wall thickness. While the technique can be reliable, the completion of a full set of measurements for a medium-sized refinery with 80,000-plus corrosion measurement points is time consuming and labor intensive, such that the wall thickness at an individual location may be measured only every 3 yr–5 yr. This is far from ideal when monitoring critical pipelines.

In addition, manual ultrasound has poor repeatability because it is unlikely that the same technician will measure at the exact same location that was measured before. The fluid flowing through the pipes also cannot be too hot, or it may damage the transducer or injure the technician taking the measurement.

A better way to measure.

Ultrasound might be an effective way to measure

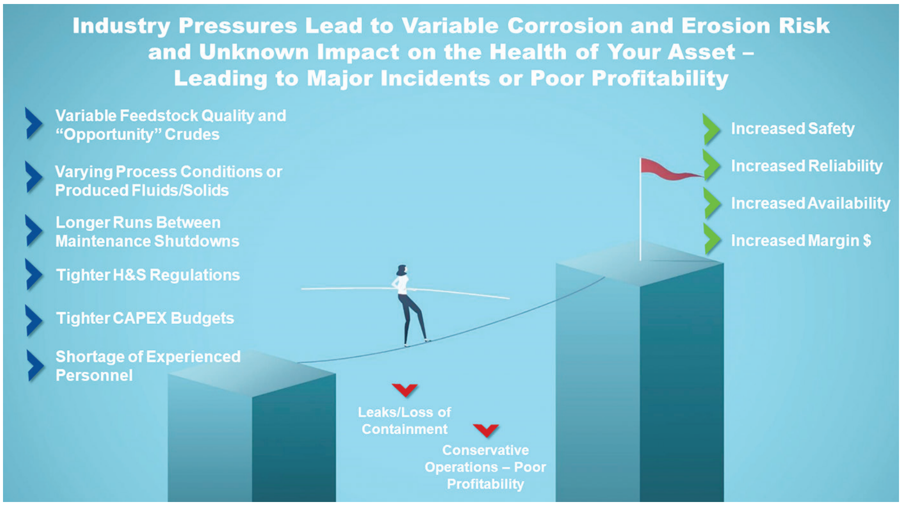

FIG. 1. Modern plant operators face a variety of challenges, requiring a tightrope balance to meeting set operational standards.

corrosion, but it requires a more reliable way of deployment to be of real use to a facility. To ensure better corrosion measurement coverage, a different ultrasound tool is becoming the device of choice in refineries. This permanently attached, continuous-monitoring ultrasonic measurement device transmits data wirelessly to a central location, thereby providing real-time measurement data-to-desk. The device attaches magnetically for easy use, can withstand temperatures up to 600°C (1,100°F), and can be deployed at scale.

There are several benefits to deploying this device:

- Instantly access real-time data to drive informed decision-making
- Eliminate risk to personnel when inspecting dangerous locations manually
- Shift from reactive to proactive maintenance.

The main benefit is that with instant data available, combined with process data, it becomes possible to gain a more complete overview of operations. It can show where potential trouble spots are growing and what type of hydrocarbon blend is moving through the pipes at what time, thereby pinpointing when trouble first emerges (**FIG. 2**).

With the increased use of more corrosive opportunity crudes, it becomes essential to know where those feedstocks might be causing problems and how to stay ahead of such issues by scheduling preventative maintenance instead of reactive maintenance.

Keeping it safe

One consideration many IT departments want to know is: How secure is the wireless data collection and transmission? These systems are built on WirelessHART, which is proven secure from the ground up. Hundreds of successful deployments of software using WirelessHART have been demonstrated across a broad array of network architectures, providing reassurance to end users.

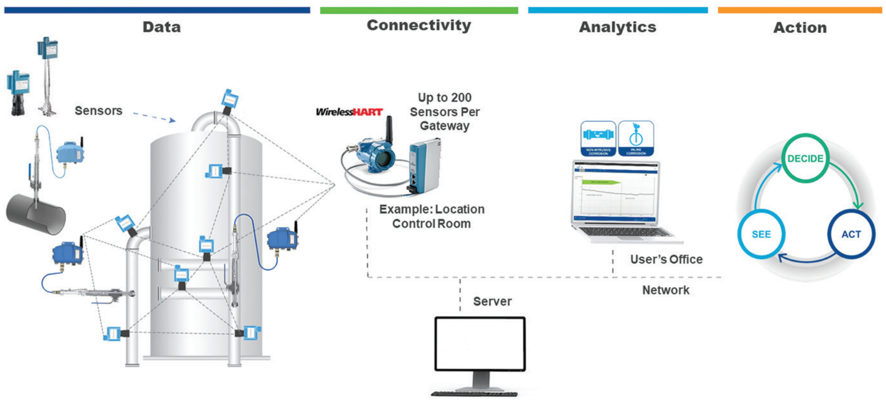

FIG. 2. A comprehensive solution of hardware and software delivers secure and reliable corrosion data data-to-desk continuously.

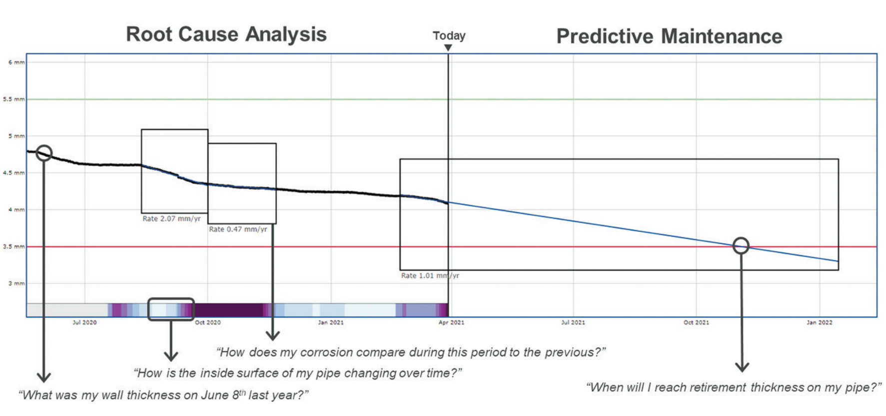

FIG. 3. Analytics inside software allow end users to perform root cause analysis, plan maintenance strategies and improve informed decision-making.

Software completes the picture. Online corrosion monitoring is only as good as the software that is used to analyze the data. Independent market research shows that corrosion monitoring software and software services are growing faster than any corrosion hardware has over the past 5 yr. Operators can now have access to an abundance of data, but if they cannot see the patterns in it or the software does not show them what is actually happening inside the facility in an easy-to-read format, then it is not useful.

Real-time asset monitoring means providing end users with continuous, consistent analytics, instead of having to download and export data, and then perform manual calculations. Pre-packaged analytics that focus on the health monitoring of plant assets, along with the corrosion application, allow end users to monitor the risk and impact of corrosion in the plant. Having this data available makes it possible to correlate wall thickness against process variables to better manage risk and drive more efficient operations (**FIG. 3**).

Better outcomes. With better quality and more current information, a refinery can mitigate risk and manage its crude strategy, choosing less favorable and cheaper feedstocks, while ensuring that the plant is operating safely. Online, non-intrusive corrosion monitoring is fast becoming a refining industry best practice with the availability of data-to-desk monitoring systems that provide previously unachievable quality and frequency of wall thickness measurements.

Maximizing operations, both in terms of productivity and profitability, while balancing the impact of corrosion on fixed assets, removes a great amount of worry and potential for unplanned maintenance shutdowns. HP

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Calculate the MTBR of pumps in an oil refinery

Mean time between repairs (MTBR) is an index for judging the performance of a specific piece of equipment. In other words, it is a measure of reliability—how long an asset typically works until it fails. It helps reliability engineers and managers make data-driven decisions on maintenance scheduling, safety, budgeting, inventory management and equipment design without relying on subjective observations. MTBR is best used for discerning whether an operating scenario is improving or worsening.

This article addresses how to calculate the MTBR of pumps in an oil refinery based on the author's experience.

Definition of pump. The first step in calculating MTBR is to define what is included (and not included) in the pump and its envelope. Pumps are equipment used to increase the pressure of a liquid from a suction to discharge pressure and include all necessary support systems, such as lubrication systems and seal support systems (**FIG. 1**).

In calculating MTBR, several points must be considered in defining the pump boundary:

- Any equipment and/or instrument in the vicinity of the pump that is not included in the pump base plate. The pump foundation, base plate, skid, support pedestals and anchor bolts should be included in the pump boundary.
- Shaft coupling that is not mounted on the pump shaft, such as the coupling between the driver and the gearbox when the pump has an external gearbox. Coupling mounted directly on the pump shaft, including the flex/rubber elements, half couplings, spacer, keys, guards, etc., should be included in the pump boundary.
- Piping flange gaskets and all piping components after the pump flanges, unions or valve installed on the pump casing must be considered in the pump boundary. Pump casing, including all flanges cast with or welded to the pump casing, is also included in the pump boundary.

  Small-bore piping connected to the pump casing up to and including the first flange, union or valve (including the valve) must be considered in the pump boundary. This includes drain, vent, cooling, external flushing and warmup lines. Mechanical seal barrier/buffer fluid lines between the reservoir and seal gland are also included.
- Steam jackets/passages that are not cast into the pump casing must be considered in the pump boundary, along with steam supply, quench and tracing systems connected to the pump but beyond the first block valve, flange or connection from the pump casing. Heat tracing placed on the outside of the pump casing and body must also be considered.
- The gasket between the main suction/discharge flange and piping system outside the pump baseplate must be included.
- Separate gearboxes, clutches and drivers with their own tag numbers must be included. Integral gearboxes built and supplied by the pump vendor with the pump must be considered in the pump boundary. This includes all internal components such as gears, bearings, seals, oil pumps, etc. Accessories mounted on the outside of the casing, such as filters, shall be considered in the pump boundary.
- Separate drivers such as motors, turbines, turboexpanders and internal combustion engines with their own tag numbers are not considered in the pump boundary.
- Lubrication system components inside the pump, such as bearing housings, oil rings, oil flingers,

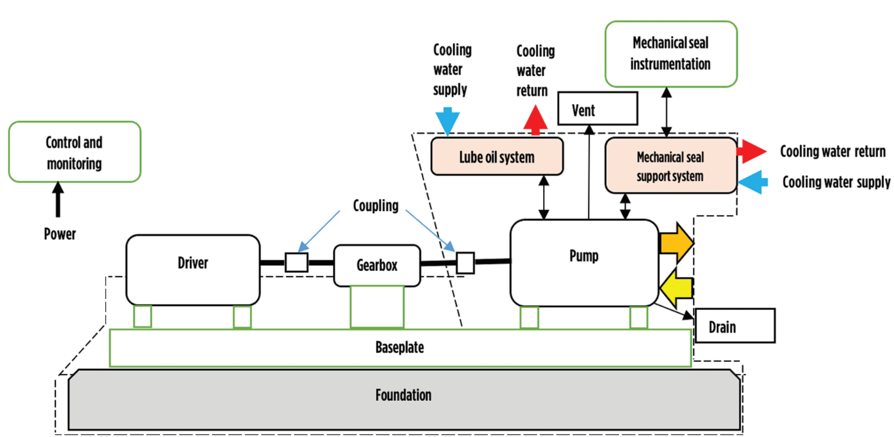

FIG. 1. Pump boundary (dotted lines) for calculating MTBR.

  - bearing seals, etc., must be considered. External lubrication systems or oil mist system components, such as filters, pumps, coolers, lubricators, oil bottles, etc., on a dedicated lube system for the pump must be considered in the pump boundary.
- Cooling water supply lines to the pump and/or heat exchangers are excluded from the pump boundary.
- Mechanical seals and packing are considered in the pump boundary.

Number of installed pumps. All the pumps that are normally present in an oil refinery must be counted as installed pumps. It is recommended to calculate MTBR based on pump type, production unit and production complexes. It may be helpful to compare the pumps installed in one refinery to the pumps present in other refineries within a single organization.

Definition of repair. The tricky part of calculating MTBR is the definition of a failure and/or the definition of repair. Before calculating MTBR, the definition of the pump repair must be first understood. A repair includes all work performed on a pump to maintain it in satisfactory operating condition.

Repair work on a pump starts when the pump is isolated from the piping system, handed to the mechanical millwright and is no longer available for use by plant operations. A pump repair is considered to be completed when all isolations for mechanical work have been removed, all mechanical locks have been removed and the pump is handed to operations for commissioning. If another failure is experienced during commissioning or restart of the pump, the resulting repair must be counted as a different, additional repair. TABLE 1 includes activities that can be considered and counted as "repair."

A case study provides better understanding of the previous explanation. On December 31, 2019, a fire occurred in the centrifugal pump of a refinery alkylation unit due to mechanical seal leakage. The fire reached the hot surface of the steam pipes, causing the alkylation unit to shut down.

The alkylation unit has 158 different types of pumps. Each pump has one standby pump. Eight pumps out of 158 are indefinitely shut down, preserved due to lack of operational need. Two different pumps were impacted by the fire, five motors were damaged and required total replacement, and the power cabling to 10 pumps skids was burned; however, the pumps were not damaged.

After inspection, management decided to do a detailed check of all spare pumps (Tag B) in hot standby mode. The other pumps (Tag A) would be run during the unit restart.

The alkylation unit was out of service for 4 weeks and was restarted on January 31, 2020. Gussets were added to the small-bore drain and vent from all the pumps, based on company specifications revised during this period. Some autonomous maintenance was planned during the shutdown period. Oil changes of the Tag B pumps were also carried out during this time. Furthermore, pump vibrations for all Tag A pumps were checked during restart.

For the 4 weeks the alkylation plant was out of service, the pump failure/repair count amounted to only two in January 2020. After unit commissioning and restart in February 2020, 16 of the main pumps (Tag A) failed within 2 weeks after unit restart.

The root causes of the failure were found to be mechanical seal failure, coupling failure, bearing failure and shaft high vibration. Therefore, the pump failure count jumped from only two in December 2019 to 16 in February 2020. A note should have been added in the MTBR report for December 2019 that 75 spare pumps were inspected and repaired after the fire; however, they should not have been counted for repair.

Mean time between repairs. MTBR is usually applied to a group of similar equipment such as pumps. The industry accepted formula shown in Eq. 1 is used for calculating the MTBR of the pump:

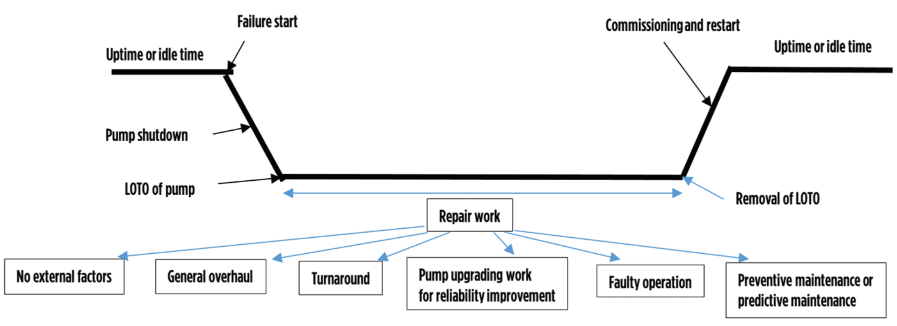

FIG. 2. Repair work visualization.

TABLE 1. Countable and non-countable repairs

Count as repair on pump boundary	Do not count as repair on pump boundary
Turnaround overhauls	Result of external factors (e.g., natural phenomena, flood, earthquake, tornado, sabotage/terrorism, unit or plant fire, lack of utility, etc.)
General overhauls	Predictive maintenance (vibration analysis) or troubleshooting not requiring a pump shutdown
Maintenance interventions require lockout/tagout (LOTO)	Maintenance interventions do not require LOTO
Upgrading to improve reliability	Upgrading due to environmental and/or safety requirement
Onsite repair work, such as packing replacement or packing ring addition by millwright	Any work outside of the pump boundary
If the root cause analysis indicates that the failure was caused by operator fault (such as running the pump dry)	Any work on the driver, gearbox and variable frequency drive

MTBR = (Total number of active pumps × time period) ÷ Number of repairs during time period (1)

"Active pump" designates a permanently installed pump that is in active service mode and available for operational use, whether its duty is continuous, standby or intermittent. The definition of an active pump does not include pumps located in units that have been indefinitely shut down, preserved or abandoned.

The longer the average time of operation between pump repairs, the greater the reliability of the pump. For example, assume that 1,200 pumps are active in a refinery over 1 yr (12 mos) and experience a total of 387 repairs during the year. The MTBR for the pumps can be calculated as shown in Eq. 2:

$$\text{MTBR} = (1{,}200 \times 12) \div 387 = 37 \text{ months} \quad (2)$$

The total number of active pumps in the plant, regardless of whether or not they are in operation, should be counted in the above formula. The following considerations are recommended during calculation of the MTBR:

- Define the pump boundary clearly and in detail.
- Calculate the MTBR for API and non-API pumps separately.
- Calculate the MTBR into specific groupings of pump types, type of mechanical seal (e.g., single seal or dual seal), type of driver, etc.
- Define the meaning of repair and/or failure clearly and in detail (see **TABLE 1**).
- In the author's experience, if MTBR is calculated over 50 months–60 months, then something may be wrong and the calculation should be checked again. If everything is correct, then celebrate your reliability improvement!

Recommendations. MTBR is the average operating calendar time between required repairs for a particular piece of machinery, type of machinery, class of machinery or operating facility. It is necessary to define the meaning of repair before calculating the MTBR.

Take care, and do not mislead plant management with an incorrect interpretation of the repair or pump boundary. It is recommended to calculate MTBR as specifically as possible based on pump type, pump classification (API/ASME), power rating, mechanical seal type and driver type. HP

NOTE

The recommendations outlined in this article are based on the author's personal experience and are not affiliated with or related to any company.

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H_2O_2 and its hydrocarbon nitridation/oxidation to produce caprolactam and propene oxide

Traditional hydrocarbon nitridation and oxidation technologies, such as caprolactam (CPL) and propene oxide production technologies, present low atom utilization and serious environmental pollution problems. An urgent need exists for green hydrocarbon oxidation and nitridation technologies. As a well-known green oxidant, hydrogen peroxide (H_2O_2) is widely used in green hydrocarbon oxidation and nitridation, with water as the only byproduct.

However, the low capacity of one single fixed-bed unit of anthraquinone hydrogenation for H_2O_2 production—which is widely adopted in China—has severely restricted the supply of H_2O_2, further hampering the development of the green chemical industry in China. The authors' company endeavors to develop slurry bed technology of H_2O_2 production to promote production capacity, reduce production costs and environmental pollution. Furthermore, green production technologies of CPL and propene oxide with H_2O_2 have also been developed. The nitrogen atom utilization was enhanced from 60% to nearly 100%, and the carbon atom utilization was also promoted from 80% to nearly 100%.

Basic organic chemicals, organic intermediates and fine chemicals usually contain nitrogen or oxygen atoms, and their production involves hydrocarbon nitridation or oxidation reactions. Traditional nitridation or oxidation reactions have poor atom utilization, and cause serious pollution due to the unsatisfactory oxidants that are used, such as dichromate, permanganate, hypochlorite and nitric acid. Ammonia (NH_3) is the fundamental source of nitrogen atom in hydrocarbon nitridation reactions, but it must experience the oxidation process to be converted into nitric acid, hydroxylamine, azide or highly toxic cyanide to participant in traditional hydrocarbon nitridation reactions. These complicated processes bring huge energy consumption and pollutants emissions. For example, more than 300 kt of nitrogen oxides (NO_x) are emitted in the NH_3 oxidation process used in nitric acid production each year.[1] Therefore, the selection of oxidant or active N-containing agent is central to promoting nitrogen or carbon atom utilization, and eliminate the generation of pollutants.

As an environment-friendly oxidant, H_2O_2 is widely used in the chemical industry, bleaching processes, wastewater treatment, exhaust air treatment and for various disinfection applications. Considering the transportation risks and costs of H_2O_2, the factory must build an H_2O_2 production unit to support the operation of the green chemical production unit. At least two H_2O_2 production units adopting fixed-bed technology should be constructed to support the normal operation of a 300 $kt \cdot a^{-1}$ propene oxide green production unit, significantly increasing construction and operating costs. Conversely, green hydrocarbon nitridation or oxidation technologies with H_2O_2 as the oxidant are developing rapidly around the world. China should also develop green chemical technologies with independent intellectual property rights to solve environmental pollution problems in its self-development process.

The authors' company has been working for more than 20 yr to develop the slurry bed technology for H_2O_2 production with completely independent intellectual property rights, supporting China's green chemical industry development.

Slurry bed technology of H_2O_2 production. The industrial production of H_2O_2 widely adopts the anthraquinone hydrogenation method due to its advantages in industrial efficiency, environmental protection and economic benefits. Its production process includes anthraquinone hydrogenation, hydrogenated anthraquinone oxidation, H_2O_2 extraction and anthraquinone working liquid purification. Two anthraquinone hydrogenation technologies are now in use: fixed-bed technology and slurry bed technology. The industrial production of H_2O_2 is also done with these two technologies.

Compared with the slurry bed technology for H_2O_2 production, the fixed-bed technology is easy to implement and the catalyst does not need to be separated. It also has the following drawbacks:

1. Heat transfer performance is poor. As the anthraquinone hydrogenation reaction is an exothermic reaction, local hot spots or flying temperatures occur in the fixed bed. The working liquid degrades easily in the high-temperature area, resulting in poor selection performance and poor product quality of the reaction, which causes subsequent processing problems and limits the capacity of the production unit.
2. Catalysts with a fine particle size cannot be used, so the inner surface with active sites is not fully utilized, resulting in low catalyst utilization efficiency. More importantly, the hydrogenation reaction is limited by heat and mass transfer.

To avoid excessive hydrogenation of the working liquid, the hydrogenation degree and hydrogen efficiency of anthraquinone are generally controlled within a

reasonable range in the actual H_2O_2 production with fixed-bed technology. Taking the current typical fixed-bed process as an example, if 120 g·L^{-1} of effective anthraquinone is completely hydrogenated, the theoretical hydrogen efficiency can reach 17 g·L^{-1}. However, due to the above drawbacks, it is difficult to increase the actual hydrogen efficiency to more than 12 g·L^{-1} in a factory.

To minimize the degradation of working liquid, the hydrogen efficiency is often controlled at 5 g·L^{-1}–8 g·L^{-1}, and the hydrogenation degree of anthraquinone is controlled at 40%–50%. Thereby, energy consumption and production costs increase. Limited by technical factors, China's H_2O_2 production has been using fixed-bed technology for many years, and the production capacity of a single unit with fixed-bed technology has never exceeded 50 kt·a^{-1}.

The slurry bed technology for H_2O_2 production shows good performance on heat and mass transfer, and the production capacity of a single unit with slurry bed technology always exceeds 100 kt·a^{-1}. Compared with the fixed-bed technology of H_2O_2 production, the industrial implementation of slurry bed technology is relatively difficult. Its technical difficulty lies in the slurry bed reactor, high-strength microsphere catalyst and solid-liquid separation system. Several chemical companies (e.g., DuPont, Solvay, Degussa, BASF) have developed slurry bed technologies of H_2O_2 production, each with their own characteristics.

The schematic of the authors' company's slurry bed technology for H_2O_2 production is shown in **FIG. 1.** The technology highlights are reflected in the following aspects:

1. It is a reaction-filtration system with a simple structure and outstanding performance in heat and mass transfers. The slurry bed reactor is equipped with a separator on the upper section that can avoid the air-resistor in the conveying pipeline and prevent the gas from entering the filter to ensure the efficient and stable operation of the filter. The slurry-containing solid catalyst particles at the bottom of the separator flow into the filter, and then solid catalyst circulates back to the bottom of the slurry bed reactor.[2,3] The slurry bed reactor lowers circulating energy consumption, and the industrial amplification is easily achieved with the advantages of high integration, simple structure and small footprint.
2. As the core of slurry bed technology for H_2O_2 production, a hydrogenation catalyst with high strength and selectivity is required. The microsphere catalyst of Pd/Al_2O_3, developed independently by the authors' company, exhibits high wear resistance, high selectivity and high activity with the synergistic effect of non-noble metals.[4] Industrial tests show the hydrogenation efficiency of the microsphere catalyst reaches 12 g·L^{-1}–13 g·L^{-1}, and no obvious change of the catalyst has been observed after the industrial test.
3. The proprietary oxygen-enriched cyclic oxidation technology improves the environmental protection, economic benefits and safety of the H_2O_2 production unit.[5] Through a compressor-assisted cycle of the oxidation tail gas, the tail gas emissions in the oxidation process are eliminated without the need for a solvent recovery device. To ensure constant oxygen supply, an oxygen-rich gas is continuously added into the recycle gas according to the consumption of oxygen. At the same time, the water brought into the oxidation tower is reduced, and the amount of residual liquid at the bottom of the oxidation tower is significantly reduced. This technology makes the H_2O_2 production greener.
4. The catalytic regeneration technology for the working liquid effectively converts anthrone into anthraquinone.[6,7] Compared with traditional regeneration technologies, the conversion rate of the catalytic regeneration technology is increased by 10 times. Moreover, the fully acidic environment not only improves the intrinsic safety of the H_2O_2 production unit, but also avoids the generation of basic alumina solid waste.

A comparison between the authors' company's slurry bed technology for H_2O_2 production and a fixed-bed technology for H_2O_2 production is shown in **TABLE 1.** Compared with the fixed-bed technology, the single-unit capacity of the slurry bed technology for H_2O_2 production is increased by 140%, hydrogen (H_2) consumption per ton of product decreased by 5%, the energy consumption and material consumption can be

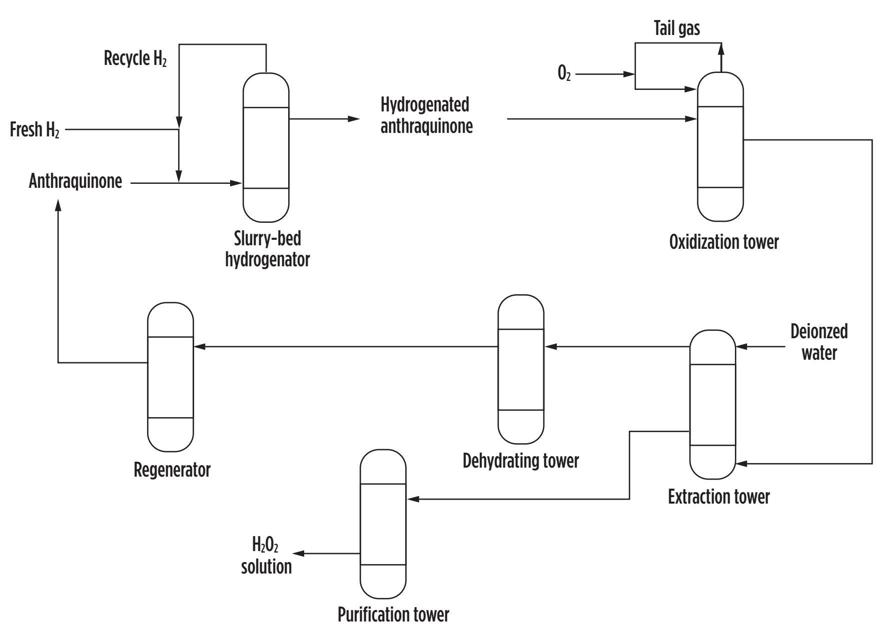

FIG. 1. Slurry bed technology for H_2O_2 production.

reduced by ~20%, wastewater and solid waste are reduced by more than 70%, and no tail gas emissions are produced. The slurry bed technology has obvious advantages in economy, greenness, intrinsic safety and productivity.

Green production technology for CPL. As the monomer for nylon-6 fiber and engineering plastics, CPL is an important basic organic chemical that is widely used in textile, automobile, electronics and other industries. More than 90% of CPL worldwide is manufactured by the rearrangement of cyclohexanone oxime. This route mainly includes hydrogenation of benzene to cyclohexane, oxidation of cyclohexane to cyclohexanone, ammoximation of cyclohexanone to cyclohexanone oxime, rearrangement of cyclohexanone oxime to CPL, and the subsequent multi-step refining processes.

Traditional CPL production technology drawbacks include:

1. Cyclohexanone oxime is synthesized by cyclohexanone hydroxylamine oxidation, which involves the oxidation of ammonia to NO_x, the absorption and reduction of NO_x to hydroxylamine, and the reaction of hydroxylamine and cyclohexanone to produce cyclohexanone oxime. This process is complex with only 60% utilization of ammonia. During the whole process, noble metal catalyst is consumed, and highly toxic NO_x is produced.
2. Cyclohexanone oxime to CPL adopts the liquid-phase Beckmann rearrangement technology. Fuming sulfuric acid is used as the catalyst, resulting in serious equipment corrosion and a large production of low-valued ammonium sulfate.
3. Unstable Raney nickel is used in the CPL purification process. This hydrogenation process is complex with a high catalyst consumption and low hydrogenation efficiency.

In view of the above deficiencies of traditional CPL production technology, the green CPL production technology developed by the authors' company provides solutions:

1. A direct cyclohexanone ammoximation technology with cyclohexanone, H_2O_2 and NH_3, in which hollow TS-1 zeolite is used as the catalyst and H_2O is the only byproduct. This technology integrates micro-sized hollow TS-1 zeolite with a slurry bed reactor fitted with a membrane separation component. A good mass transfer performance of the reaction system has been developed. The micro-sized hollow TS-1 zeolite is prepared by hydrothermal synthesis with secondary structural modification technology, and its stability is improved by adding silicon-containing additives.[8,9,10] In this direct cyclohexanone ammoximation technology, the cyclohexanone conversion is more than 99.9%, and the cyclohexanone oxime selectivity is more than 99.5%. The new technology markedly simplifies the cyclohexanone ammoximation process, improves the utilization of NH_3 from 60% to > 90%, decreases the plant investment by > 70%, reduces 99.5% of exhaust emissions, and eliminates the production or use of corrosive NO_x. As a result, the production cost of cyclohexanone oxime is reduced by 800 $CNY{\cdot}t^{-1}$.
2. A gas-phase Beckmann rearrangement of cyclohexanone oxime to CPL by integrating silicalite-1 zeolite with a moving-bed reactor.[11,12] The use of fuming sulfuric acid is avoided, and no ammonium sulfate is produced. As a result, there is no equipment corrosion nor pollutant emissions. The cyclohexanone oxime conversion is higher than 99.9%, and the CPL selectivity is around 96.5%. The nitrogen atom utilization is increased from 36% to near 100%. The production cost can potentially be reduced by 1,000 $CNY{\cdot}t^{-1}$.

FIG. 2. A 400-$kt{\cdot}a^{-1}$ CPL industrial production plant. Source: Sinopec.

TABLE 1. Comparison of different technologies for H_2O_2 production

Technology	Working liquid	Hydrogenation efficiency, $g{\cdot}L^{-1}$	Working liquid loss, $kg{\cdot}t_{H2O2}^{-1}$	Energy consumption, $kWh{\cdot}t_{H2O2}^{-1}$	Regeneration	Capacity, 10 $kt{\cdot}a^{-1}$
Slurry bed (authors' company)	AR+TOP+EAQ	12–13	2.03	600	Acid, safe	12
Fixed-bed	AR+TOP+EAQ	7–8	2.54	742	Al_2O_3, explosion risk	5

Note: AR, heavy aromatics; TOP, trioctyl phosphate; TBU, tetrabutyl urea; 2-MCHA, o-methyl cyclohexyl acetate; EAQ, ethyl anthraquinone; AAQ, amyl anthraquinone

3. Integration of amorphous nickel with a magnetically stabilized bed. The large-radius, rare-earth atoms are introduced into amorphous nickel to improve the catalyst thermal stability, and the surface area is improved by the method of "adding-leaching aluminum."[13] Magnetic retainer internals are developed to ensure the uniformity of the magnetic field in the magnetically stabilized bed.[14] As a result, unstable Raney nickel catalyst is not used, and the operation cost of the CPL production unit is reduced significantly.

The first industrial plant based on the authors' company's CPL green production technology with a capacity of 70 kt·a^{-1} was built in 2003. **FIG. 2** shows a 400-kt·a^{-1} CPL production plant with green production technology. Compared with traditional CPL production technology, the green CPL production technology reduces the exhaust gas by 95%, no low-valued ammonium sulfate is produced, and the overall investment can drop by 70%. A CPL production unit with a capacity of 50 kt·a^{-1} can reduce 2.4×10^8 m^3 of waste gas emissions and 80 kt of low-valued ammonium sulfate production every year.

The proprietary green CPL production technology has strongly supported the technological upgrading of CPL production in China. In 2020, China's CPL capacity based on this green production technology reached 4,000 kt·a^{-1}, giving China a global market share that exceeds 50% and making it the world's largest CPL producer—a huge leap from China's original position of relying almost totally on CPL importation. The green CPL production technology also sets a successful example of green hydrocarbon nitridation.

Green production technology of propene oxide. As the third-largest propene derivative, propene oxide is widely used in unsaturated resins, surfactants and polyurethanes. In 2020, the actual output of propene oxide in China was 2.9×10^6 t, compared to a global output of approximately 1.05×10^7 t.

Traditional industrial production processes of propene oxide include the chlorohydrin process and co-oxidation process. Hypochlorous acid is used as oxidant in the chlorohydrin process, resulting in serious equipment corrosion and environmental pollution. When producing 1 t of propene oxide, the chlorohydrin process consumes 1.35 t–1.85 t of chlorine gas, and produces 40 t–80 t of chlorine-containing wastewater and more than 2 t of calcium chloride ($CaCl_2$). Though the construction of new plants for producing propene oxide with the chlorohydrin process has been strictly controlled since 2011, the chlorohydrin process still accounts for more than 50% in the production of propene oxide in China.

To overcome the disadvantages of the chlorohydrin process, the co-oxidation process was developed. Though the co-oxidation process solves the equipment corrosion and environmental pollution problems, the co-oxidation process with ethylbenzene or isobutane as a co-reductant is complicated, and requires harsh reaction conditions that necessitate high-quality equipment material. This results in high equipment costs. Additionally, the quality of propene must be high, and the economic benefit is restricted by the co-products, as 2.2 t–2.5 t of styrene or 2.3 t of tert-butanol is produced when producing 1 t of propene oxide. The co-oxidation route with cumene as co-reductant does not produce co-product, but it does consume significant energy due to the separation and conversion of intermediate products. Additionally, it requires the construction of a large-scale oxidation unit of cumene.

Technologies for propene oxide production by direct epoxidation of propene have been developed in recent years. Among them, the direct epoxidation technology with H_2O_2 as the oxidant and TS-1 zeolite as the catalyst (HPPO process) is the most mature, and it has been industrialized. Compared with the chlorohydrin method, the C atom utilization of the HPPO process is close to 100%, with reductions in equipment in-

Traditional nitridation or oxidation reactions have poor atom utilization and cause serious pollution due to the undesirable oxidants that are used. Green hydrocarbon oxidation and nitridation technologies with green oxidants are urgently needed.

FIG. 3. A 100-kt·a^{-1} propene oxide industrial production unit. Source: Sinopec.

vestment (25%), wastewater discharge (70%–80%) and energy consumption (> 35%). The authors' company began research on its HPPO process in 2003, and put it into industrial demonstration on a 100-$kt\cdot a^{-1}$ unit, which is shown in **FIG. 3.** Process highlights include:

1. A hollow TS-1 zeolite with Si enriched on the surface.[15,16] The company found that the acidity of catalyst is the main factor that accelerates the solvolysis of propene oxide, and the acidity comes from Ti active centers, trace Al, defects of surface and lattice in TS-1 zeolite. Therefore, the synthesis process of the hollow TS-1 zeolite was modified to enrich Si on the surface of hollow TS-1 zeolite—which is different from the hollow TS-1 zeolite used in the cyclohexanone ammoximation reaction—increasing the selectivity of propene oxide to higher than 95%.
2. Amorphous SiO_2 and other additives are added into the hollow TS-1 catalyst to increase the crushing strength of the catalyst to higher than 120 $N\cdot cm^{-1}$ without decreasing the catalyst activity and fixed-bed reactor utilization.[17,18,19] The conversion of H_2O_2 could reach higher than 96% with 95% selectivity of propene oxide.
3. The in-situ catalyst regeneration technology of deactivated catalyst with solvent extraction was developed by the authors' company.[17] The life span of regenerated catalyst is equivalent to fresh catalyst, and the catalyst activity is well restored.
4. A two-stage, fixed-bed reactor in series was adopted.[17] This technology not only solves problems caused by the strong exothermic effect of the HPPO process, but also realizes the continuous production of propene oxide combined with the in-situ catalyst regeneration technology.

The company has successively developed the synthesis technology of hollow TS-1 zeolite with Si enriched on the surface, the preparation technology of high-strength hollow TS-1 catalyst with high-selectivity, the in-situ regeneration technology of deactivated catalyst, the design and manufacturing technology of large-scale tubular reactor, and the safety control technology of the whole process. The 1 $kt\cdot a^{-1}$ pilot-scale test shows that the HPPO process can convert 96%–99% H_2O_2 with a 96%–98% selectivity of propene oxide. After the catalyst runs for 6,000 hr, no significant change in activity was detected.[17] In 2020, the technology package of the HPPO process with a capacity of 300 $kt\cdot a^{-1}$ passed the technical appraisal.

Takeaway. The authors' company has developed full-process green chemical technologies of CPL and propene oxide production, including an important supporting technology: the slurry bed technology for H_2O_2 production, which provides a stable and reliable source of H_2O_2 for the development and industrial implementation of green chemical technologies. A 120-$kt\cdot a^{-1}$ slurry bed production unit of H_2O_2 is sufficient to support the effective operation of a 300-$kt\cdot a^{-1}$ production unit of propene oxide.

The slurry bed technology for H_2O_2 production and green hydrocarbon nitridation/oxidation technologies with H_2O_2 to produce CPL and propene oxide developed by the authors' company have provided the whole-process technical support for two chemical production bases: Gulei and Baling. The Baling offsite construction project was regarded as a benchmark by the Chinese government for the relocation of hazardous chemical production plants along the Yangtze River. The production technologies for H_2O_2, CPL and propene oxide have greatly promoted the development of China's green chemical industry. HP

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Assessment of independent protection layers in an LOPA study—Part 1

Industrial facilities, especially those operating in the chemical, oil and gas and petroleum industries, contain inherent risks in operations due to the processing of materials that are hazardous in nature. Hazards, operability issues, associated risks and their consequences must be accurately identified and analyzed to ensure safe operations. Safety instrumented systems (SISs) are deployed to reduce risk to tolerable or acceptable levels to achieve safe operations.[1] The reliability of safety functions implemented in an SIS is determined by the magnitude of risk reduction required and is expressed in terms of safety integrity level (SIL).

A layer of protection analysis (LOPA) is one of the methods used to determine the SIL of the safety instrumented function (SIF). During the LOPA study, the design is thoroughly examined for one or more independent protection layers (IPLs) in the design to assess whether the required risk reduction has been achieved. The success of the LOPA study depends on proper assessment of the protection layers and their contribution to risk reduction.

This article reviews the attributes of IPLs for their effective consideration in an LOPA.

If used improperly, any SIL selection method may lead to an inappropriate SIL target with a potentially intolerable level of risk. Qualitative methods like a safety layer matrix and risk graphs are simple, easy-to-use, less time-consuming and can be used in a project's early stages to screen a large number of SIFs. However, this tends to be more conservative and may result in a higher SIL requirement, eventually leading to increased costs.

Semi-quantitative methods like calibrated risk graphs and LOPA methods are more quantitative in nature and, therefore, more precise than qualitative methods. They can be used during the detailed engineering stage of the project, or when it is necessary to validate/review previous results from qualitative/semi-qualitative methods. However, this is more time-consuming and requires more resources than a qualitative method.

Among fully-quantitative methods, quantitative risk analysis (QRA) is the most resource intensive. QRA is uncommon in the process industries, but has been used to analyze cases where the risk is extremely high. Fault tree analysis (FTA) or event tree analysis (ETA) methodologies are used to evaluate the scenarios in detail and provide more exact results [e.g., a minimum value of risk reduction factor (RRF) that is required for SIF].

It is important to select the most appropriate method for an SIL study. A LOPA is a widely accepted method for SIL determination in the process industries—within the LOPA study, it is vital to select and carefully evaluate IPLs to achieve the most appropriate result for SIL assignment.

LOPA PROCESS

The starting point for a LOPA is to utilize data collected and developed in a hazard and operability (HAZOP) analysis. **FIG. 1** shows different data from a HAZOP that will be used directly for the LOPA study.

The first step in a LOPA study is to define the impact event, which is taken from the "consequence" data field of the HAZOP. In the second step, consequence severities or severity levels [i.e., minor (M), serious (S) or extensive (E)] are designated for the selected impact event. In Step 3, all applicable initiating causes of the impact event are listed. Step 4 determines the likelihood values of the initiating causes, in the number of events per year. The team's experience is vital in determining the frequency of initiating causes. The next step in the LOPA process is identifying all possible protection layers with their probability of failure on demand average (PFDavg) values. The LOPA team must be very careful while selecting the appropriate protection layers—protection layers that perform their function with a high degree of reliability may only qualify as IPLs. These selected IPLs will drastically reduce the risk to the process and may impact the overall result if not selected properly. **FIG. 2** is part of a worksheet for conducting an LOPA study.

The intermediate event likelihood is computed by multiplying the initiating likelihood (Column 4) by the PFD values of the protection and mitigation layers in the following step (Columns 5, 6 and 7). This calculated result is the number of events per year and is entered into Column 8. If the intermediate event likelihood is greater than the corporate criteria for events of this severity level, additional mitigation is required. Inherently safer methods and solutions should be considered before additional

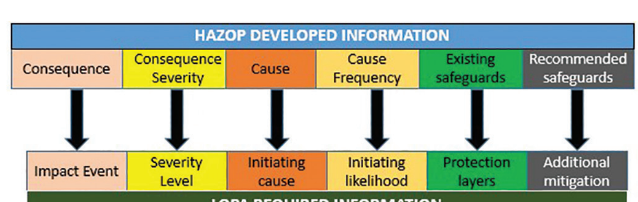

FIG. 1. LOPA-required information from a HAZOP.

1	2	3	4		5		6	7	8	9	10	11
				Protection layers								
Impact Event	Severi ty Level	Initiating cause	Initiating likelihood	Process design	BPCS	Alarms	Restrict ed access	Dike, Pressure relief	Intermedia te likelihood	SIL	Mitigated event likelihood	Notes

FIG. 2. LOPA templates for conducting a thorough study.

protection layers in the form of SIFs are applied.

If intrinsically safe design improvements are possible, the intermediate event likelihood is reassessed to determine if it meets corporate requirements. An SIF is required if the measures to reduce the intermediate likelihood below corporate risk standards fail. In Step 7, the SIL for a new SIF is defined and can be calculated by dividing the corporate criteria for this severity level of event by the intermediate event likelihood. The SIF PFDavg below this number is selected as the maximum value for the SIF and entered in Column 9. In Step 8, the mitigated event likelihood is then calculated by multiplying Columns 8 and 9, and the result is entered in Column 10. This is continued until the team has calculated the mitigated event likelihood for each impact event that can be identified. In the final step of the LOPA, total risk is calculated by adding the mitigated event likelihood for serious and extensive impact events that present the same hazard. The LOPA is complete if it satisfies or is lower than the corporate criteria for the population impacted.

Selection of IPLs. A process plant can have different protection layers available to protect the process from undesirable events. Some IPLs (prevention layers) are used to thwart hazardous events, while other IPLs (mitigation layers) reduce the severity of the consequences of hazardous events. When the frequency of the initiating event or the severity of the consequences are high, it may be necessary to apply more than one IPL to reduce the risk to a reasonable or tolerable level. As a result, it is critical to select the correct safeguards and consider the appropriate credit in risk reduction.

Core attributes to qualify protection layers as successful IPLs. During the LOPA analysis, the team selects the credible IPL from the available safeguards for a particular scenario when determining the system's target risk. Before choosing it as a credible IPL, each safeguard must be carefully examined and certain aspects/attributes must be considered, including:

- Independence
- Functionality
- Integrity
- Reliability
- Access security
- Auditability.

Each of these main attributes is explored in greater depth in the following sections of this article.

Independence. The first fundamental attribute is independence, meaning that any protection layer must be independent of other available layers of protection and of the initiating event (IE). Independence can only be achieved if the performance of the selected protection layer or its components is unaffected by the function/failure of another IPL or IE. This core attribute has different characteristics that must be considered.

Dependent safety systems. Scenarios exist in which the safety system can only act efficiently if another system operates partially effectively—such a dependent safety system is very common to oil and gas refinery processes.

In refineries, pressure relief devices protect against over-pressure scenarios: for example, a pressure relief valve (PRV) protects a vessel from rupture. As required, these PRVs are provided with cladding or insulation in case of fire. If the PRV is sized appropriately, the PRV cannot be given sole credit as an IPL. The PFDavg of both the cladding and PRV must be factored to consider this as an IPL. For this scenario, the insulation and cladding must be specified as "fire-resistant" and constructed of appropriate materials (e.g., calcium silicate with stainless-steel cladding). All hazard evaluations begin with the presumption that operations conduct adequate preventative maintenance. If the PRV is not sized for a pool fire when warranted, the PRV must be appropriately sized.

Another example of a dependent system is the PRV on a feed surge drum. A discharge pump will pump the material from the surge drum to a high-pressure system (i.e., reactors downstream of the surge drum). Normally, the PRV is sized to protect the feed surge drum from over-pressure and not sized for full reverse flow from the high-pressure system when the discharge pump fails. If a discharge pump malfunctions, it is possible for the high-pressure system stream to enter the feed surge drum. In such scenarios, the PRV cannot be considered an IPL. This high-pressure reverse flow can be prevented by providing double-check valves to the discharge piping of the discharge pump. To consider the PRV as an IPL, the double-check valves must successfully perform their intended functions. Good engineering practices recommend that the PRV is sized by considering the leakage reverse flow (at least 10% of the piping diameter) from the double-check valve assembly.

During the LOPA study, the team should analyze the IPL if it depends on the activation of other components, and credit should be given to the component for the IPL.

Common mode failure. Another important characteristic of independence is the common mode failure—the failure of any one component may impact the functioning of two or more devices, equipment or system. High-temperature reactors are common in refineries. The discharge piping of such reactors has a very high temperature and thorough monitoring and control are required. If the temperature monitoring of this piping is done with a common tapping point [i.e., a metal "T" for a basic process control system (BPCS) as well as for an SIS], this may result in a common cause failure of the metal T due to erosion, corrosion and plugging. In such cases, a BPCS alarm cannot be credited as an IPL. The LOPA team should recommend providing the individual tapping point for both the BPCS and SIS temperature measurement if the construction of the reactor allows.

Functionality. Safeguards that can be credited as an IPL must be verified from a functionality perspective: the IPL must perform its intended purpose under actual process conditions to prevent the hazardous event or mitigate the effects of the scenario being studied. An operator action in response to an alarm can sometimes be considered as an IPL, but the allowable process safety time (PST) must be verified by the LOPA team to ensure that sufficient time for action is available. PST is defined as the time between the initiating event and when the process moves into the dangerous failure state. Clearly written, step-by-step proce-

dures detailing necessary actions must be available to be credited as an IPL. Time of operator action varies for different process scenarios, but > 20 min is considered a reasonable period.

Demands on a process or system may impact personnel, assets and the environment, and the severity of consequences vary.

If a scenario yielded a target SIL-2 for assets, an SIL-3 for the environment and an SIL-1 for personnel protection, the total target SIL would be SIL-3 due to the conservative values among the three. Since environmental protection is the governing case in this example, if the safeguard is considered a credible IPL and can reduce the risk to the order of magnitude (OoM) of 1 or 2, its function must be verified to determine whether it mitigates the consequences associated with environmental protection or not.

If the over-pressure scenario is mitigated for a PRV as an IPL for SIL-3 safety function (remember that the target SIL-3 is assigned for environmental safety), then the function or intent of this PRV must be to reduce the risk of environmental harm when it operates. This means that rather than being vented open to the atmosphere, the PRV should be controlled to closed containment or sent to a knockout (KO) drum, and then released through the stack after treatment at a safe location.

Integrity. IPL integrity is defined as the magnitude or effectiveness by which the IPL reduces the risk, as expressed by the probability of failure on demand PFD values or some time OoM (e.g., if an IPL claimed a PFD of 0.01, the OoM is 2; if the PFD claims 0.1, the OoM is 1). This OoM can be directly related to the SIL number. For example, if the SIL of a particular SIF loop (before being considered an IPL) is SIL-2, then it can be reduced to SIL-1 for an OoM of 1 (i.e., a PFD credit of 0.1 for the IPL).

IPL integrity depends on the integrity of its components and its intended function; for example, if the operator action on an alarm is considered as an IPL and the PFD value claimed is 0.1, then the IPL integrity depends on the reliability of the transmitter and associated control system (BPCS) that generates the alarm, as well as when and how the operator reacts. It is recommended to perform frequent checks, such as functional testing, proof testing, verification and validation, for sensors and the control system. Similarly, the integrity of operator actions can be ensured with written procedures, regular training and verification of the training's effectiveness.

For some IPLs, functional testing, trial runs or simulations are recommended to verify effectiveness. Ultimately, a proper safety management plan should be implemented, reviewed and audited as per the functional safety standards IEC 61508[2] and IEC 61511.[3] Management is responsible to effectively implement the safety plan throughout the organization.

The Center for Chemical Process Safety (CCPS) has provided general PFD values for IPL credit, as well as the requirements for applying these values to a specific IPL and its limitations.[4] The final decision to use the PFD values, however, is subject to client approval.

Example. An example of considering the SIL-2/SIL-3 SIF as a credible IPL is the LOPA study explained here. Consider an incinerator package, which is commonly used in sulfur recovery units (SRUs) in refineries. Full combustion in the incinerator is vital to achieve the highest efficiency of this equipment.

Maintaining the air-to-fuel ratio in the incinerator is critical for full combustion. Air-to-fuel control is typically implemented in a distributed control system (DCS) with a robust ratio controller and a sophisticated control algorithm. Other DCS controls include main fuel gas control, incinerator temperature controls, combustion air flow control, O_2 trim controls, secondary air flow control, and a variety of others. Aside from process controls via a DCS, an SIS is used to implement safety functions. The incinerator also has its own SIL-3 rated programmable logic control (PLC)-based burner management system (BMS) that oversees the entire process from burner start to safe shutdown. Even with such sophisticated controls in place, a risk remains that a demand can arise in the system that places the plant in a dangerous situation.

If the air-to-fuel ratio fails due to various reasons, what happens to the plant and the incinerator? The first obvious issue is that proper fuel combustion is not taking place, potentially putting the plant in duress. Combustion or primary air failure can result in a flickering flame, which can cause an incinerator flame-out condition. In the worst-case scenario, this could result in an incinerator explosion. The most serious damage to an incinerator is the possibility of an explosion in the furnace if the incinerator is restarted without effectively purging out the combustible hydrocarbon gases from the system.

In case of failure of primary air, the credit for the robust SIL-3 SIF of the burner management system can be taken as an active IPL with a risk reduction factor of OoM 3 with reference to IEC 61511-3, Table G.6.[3] The effective IPL would be, "Incinerator start logic incorporates necessary purge time and volume with combustion air before ignition sequence is permitted and isolation of sour gases." The temperature in the burner's combustion zone would be between 1,400°C–1,700°C. To avoid damage to the burner internals due to overheating from the hot flue gases and radiation from the chamber, a positive purge flow through the burner and incinerator is necessary. Combustion air may be used to purge the incinerator unit. To avoid damage to the refractory lining, the cooling of the device must be done in a regulated manner.

As a result, the integrity of this BMS purging system now becomes vital because it is being credited as an active IPL. During the LOPA study, the team should thoroughly discuss and document such IPLs to maintain IPL integrity. The LOPA team should also recommend that this IPL complies with all functional safety requirements according to safety lifecycle phases, which begin with design and end with decommissioning.

The remaining attributes, reliability, access security and auditability will be discussed in Part 2, which will appear in the December issue. HP

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HP | Hydrogen

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Monitoring hydrogen plant performance—Part 2

Process monitoring is an indispensable practice to keep track of KPIs of an H_2 plant. A good system of process monitoring not only ensures safe and reliable plant operations, but also helps operators to make strategic decisions, such as for catalyst changeout schedules. If KPIs are not monitored closely, there can be situations where the expected yields are not achieved. This affects the economics of the H_2 plant and the entire refinery complex.

The main objectives of this article are to guide H_2 plant process engineers in monitoring critical parameters and KPIs across each reactor in the H_2 flowsheet, and in performing a detailed mass balance across the H_2 flowsheet by using available information, such as dry analysis of outlet streams. Doing so will help identify bottlenecks across each reactor. The focus would be to see how much H_2 is being produced before the final stream enters the pressure swing adsorption (PSA) unit.

This mass balance will also help estimate the outlet stream's composition on a wet basis, thereby facilitating the estimation of equilibrium constants (K_{eq} values) for steam methane reforming (SMR) and water-gas shift (WGS) reactions, which will help calculate the approach-to-equilibrium (ATE) values. These values, which are important in understanding the catalyst activity, can then be compared with the kinetic model values provided by the catalyst supplier.

Primary steam reformer. Every H_2 process engineer knows that the primary steam reformer is the heart of the entire H_2 flowsheet. The primary function of the unit is the conversion of methane and higher hydrocarbons (in the absence of a prereformer) in the feed to H_2 (along with CO and CO_2). Key parameters include the steam-to-carbon (S/C) ratio, outlet temperature, pressure, pressure drop, tube wall temperature (TWT), reformer firing and flame characteristics, and tube appearance. Methane conversion (as indicated by methane slip) and pressure drop are the two major performance indicators.

TABLE 5. Inlet/outlet of Case 1

	Inlet, kmol/hr	Outlet, kmol/hr
H_2	223.76	0.724*d*
N_2	49.72	0.0135*d*
CH_4	907.47	0.0457*d*
CO_2	62.16	0.081*d*
CO	0.373	0.1361*d*
H_2O	2,785.32	*s*

Approach to equilibrium is a theoretically important parameter in this section, as it indicates the performance of catalyst, while other parameters (such as outlet temperature, S/C ratio and pressure) are held constant. This value will be useful for the process engineers during the technical evaluation stage concerning catalyst offers. The reactions occurring in the reformer are equilibrium limited; therefore, the methane slip observed at zero (or close to zero) ATE indicates the minimum possible thermodynamically methane slip at the given conditions.

Another advantage of calculating the equilibrium temperature is that it provides an indication of the exact outlet process gas temperature. As the WGS reaction is quick, it can be assumed to always be in equilibrium at the reformer outlet conditions.

Normally, in most reformers, the reformer outlet temperature indication (TI) is located a few meters away from the tube outlet (where the catalyst ends). There is always some heat loss that needs to be assumed from the tube end to the TI point.

Mass balance across the primary reformer. The pre-reformer effluent is the feed to the reformer. Depending on the flowsheet, there could be some additional steam added at the reformer inlet. For reformers in hydrogen and carbon monoxide (HyCO) plants, recycled CO_2 is normally added at the reformer inlet, with the intention to maximize CO yield. However, for the examples here, let us assume that no additional steam is added for Case 1 and that some steam is added for Case 2. **Note:** These are purely assumptions and bear no similarity to any existing unit.

Case 1. The total wet flow at the outlet of the pre-reformer—as per the calculation detailed in Part 1 of this article—was 4,028.4 kmol/hr. The reformer inlet temperature was 500°C, and the reformer's outlet temperature was 840°C. Assuming 15°C heat less from the tube end to the TI, the tube outlet temperature would be 855°C and the outlet pressure would be 22 bara (21.7 atma). The outlet composition (dry basis) reported by the laboratory was the following:

- H_2 = 72.4%
- CH_4 = 4.57%
- CO = 13.61%
- CO_2 = 8.1%
- N_2 = 1.35%.

In the following equation for this example, *d* is the outlet dry flowrate and *s* are the moles of steam at the outlet. The inlet and outlet moles in Case 1 are shown in **TABLE 5.** To calculate *d* using carbon balance, Eq. 20 is used:

$$907.47 + 62.16 + 0.373 = 0.0457d + 0.081d + 0.1361d \quad (20)$$

d (the outlet dry flowrate) = 3,691 kmol/hr

To calculate s using O balance, Eq. 21 is used:

$$2 \times 62.16 + 0.373 + 2785.32 = s + 2 \times 0.081 \times 3691 + 0.1361 \times 3691 \quad (21)$$
s (the outlet steam) = 1,809.73 kmol/hr

The outlet wet mol fraction is shown in **TABLE 6.** To calculate the SMR equilibrium constant, Eq. 22 is used:

$$Kp\,(SMR) = P^2 \times [([CO]\,[H_2]^3)/([CH_4][H_2O])] = 21.7^2 \times (0.091 \times 0.486^3) \,/\, (0.031 \times 0.329) = 482.3 \quad (22)$$

Eq. 22 can be substituted with Eq. 23 to obtain equilibrium temperature in °K:

$$\mathrm{Ln}\,(1/Kp) = 0.2513Z^4 - 0.3665Z^3 - 0.58101Z^2 + 27.1337Z - 3.2770 \quad (23)$$

where $Z = (1000/T)^{-1}$; T is in °K
$\mathrm{Ln}\,(1/Kp) = -6.179$
Solving the equation using Excel, the answer is T_{eq} = 846.3°C. Therefore, the approach to SMR equilibrium in the reformer is $T - T_{eq}$ = 855 – 846.3°C = 8.7°C. The WGS approach can be calculated using Eqs. 24 and 25:

$$Kp\,(WGS) = [([H_2][CO_2])/([H_2O][CO])] = (0.486 \times 0.054) \,/\, (0.329 \times 0.091) = 0.8766 \quad (24)$$

$$\mathrm{Ln}\,(K_p\,WGS) = 0.63508Z^3 - 0.29353Z^2 + 4.1778Z + 0.31688 \quad (25)$$

Solving the equation, using Excel, $T_{eq\,(WGS)}$ = 845.9°C.

Case 2: The naphtha case. Assume that additional steam of 165 kmol/hr is added at the inlet of the reformer. The reformer's inlet temperature is 500°C, and the reformer's outlet temperature is 840°C. Assuming 15°C heat loss from the tube end to the TI, the tube outlet temperature is 855°C, and the outlet pressure is 23 bara (22.7 atma). The outlet composition (dry basis) reported by the laboratory was the following:

- H_2 = 68.53%
- CH_4 = 2.76%
- CO = 15.86%
- CO_2 = 12.85%.

TABLE 6. Outlet wet mol fraction for Case 1

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	223.76	2,672.3	0.486
N_2	49.724	49.83	0.009
CH_4	907.47	168.68	0.031
CO_2	62.156	298.97	0.054
CO	0.373	502.35	0.091
H_2O	2,785.32	1,809.71	0.329

TABLE 7. *C* and *O* balance for Case 2

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	122.39	973.14	0.417
H_2O	1,064.53	915.48	0.392
CO_2	136.63	182.47	0.078
CH_4	307.41	39.19	0.017
Additional H_2O	165		

The outlet wet composition after completing C and O balances is shown in **TABLE 7.** Solving the equations as before, we receive the following:
$K_{p(SMR)}$ = 538.3; $K_{p(WGS)}$ = 0.864
$T_{eq(SMR)}$ = 851.4°C; $T_{eq\,(WGS)}$ = 850.1°C.
Therefore, the approach to SMR equilibrium in the reformer is $T - T_{eq}$ = 855 – 851.4°C = 3.6°C. The process engineer should ask the catalyst supplier what the expected approach is and compare the same with the calculated values.

Tube wall temperature. Besides catalyst activity, the approach also depends on operating conditions such as outlet temperature, pressure and composition, as well as how the reformer is being operated. Additionally, the approach and the methane slip depend on how the reformer is being operated. Improper heat distribution across the tubes will increase the approach; therefore, the methane slip would be more than expected, although the catalyst is perfectly normal in terms of its activity.

Tube wall temperatures need to be measured on a regular basis, using a simple handheld pyrometer or advanced thermal imaging equipment. The TWT of all tubes—after applying a suitable correction for background radiation—should indicate the reformer heat distribution balance. A spread (maximum–minimum) of more than 70°C normally indicates that there is scope for improving the heat distribution. The measured TWT of tubes can also be compared with the expected TWT profile as per the catalyst supplier's kinetic model.

Pressure drop across the steam reformer. This is another critical parameter that needs close monitoring. The rate of pressure drop increase depends on how well the reformer is being operated. Due to the expansion and contraction of tubes, frequent trips or shutdowns can break the catalyst pellets. The broken pellets can contribute to a higher pressure drop. A sudden increase in pressure drop would need the time to be isolated and for any event in that period to be investigated. In most plants, the pressure drop is measured between the reformer inlet and waste heat boiler (WHB) or process gas boiler (PGB) outlet.

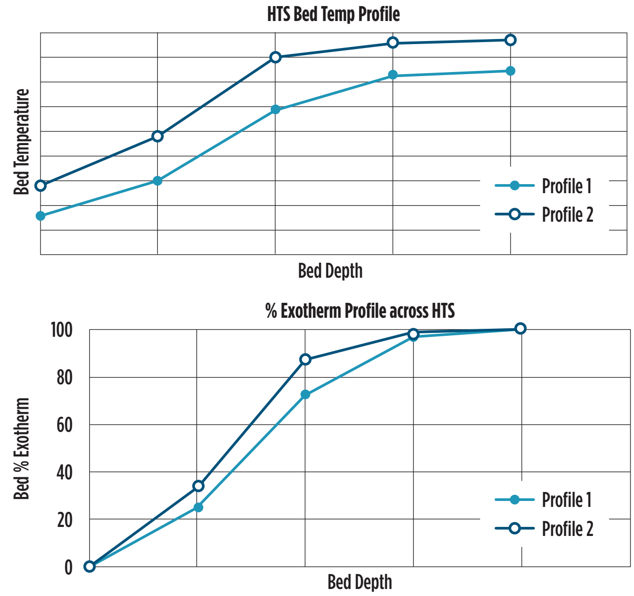

FIG. 3. HTS bed temperature profile (top) and the percent exotherm profile across the HTS (bottom).

TABLE 8. *C* and *O* balance for Case 1 (shift reactor)

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	2,672.3	3,038.25	0.552
N_2	49.83	49.92	0.009
CH_4	168.68	168.84	0.031
CO_2	298.97	663.98	0.121
CO	502.35	137.18	0.025
H_2O	1,809.71	1,444.85	0.263

TABLE 9. *C* and *O* balance for Case 2 (shift reactor)

	Inlet, kmol/hr	Outlet, kmol/hr	Outlet wet mol fraction
H_2	973.14	1,147.25	0.491
H_2O	915.48	741.34	0.317
CO_2	182.47	356.64	0.153
CO	225.24	51.02	0.022
CH_4	39.19	39.22	0.017

Therefore, any fouling in the WHB/PGB can also affect the pressure drop. The process engineer should have a record of the number of trips/shutdowns and the reason for such a trip/shutdown. In many instances, a step increase in pressure drop is observed after starting up after a sudden trip.

Shift reactor. The primary function of the shift reactor is to convert CO formed in the reformer to H_2 by reacting it with steam. The key parameters are inlet temperature, outlet temperature, steam-to-dry gas ratio, pressure drop and temperature profile. The KPIs include CO conversion, pressure drop and WGS approach.

Plotting the temperature profile clarifies how the catalyst activity declines with age. A clear trend can be obtained by plotting the percent exotherm profile rather than the temperature profile. The percent exotherm at any bed temperature equals $[(T - T_{min}) / (T_{max} - T_{min})] \times 100$. A sample illustration of both bed temperature and exotherm percentage plots across a high-temperature shift (HTS) reactor is shown in FIG 3. Profiles 1 and 2 are different profiles for the same feed at different inlet temperatures. Not much can be inferred by plotting the bed temperatures. However, when the profiles are plotted by taking the exotherm percent at each position, it becomes clear that, by increasing the inlet temperature, the reaction profile becomes steeper.

Pressure drop. The shift reactor, either HTS or medium-temperature shift (MTS), being downstream of the WHB/PGB, is vulnerable to fouling issues due to upstream boiler water leaks. This causes pressure drop to increase due to the buildup of boiler solids. The pressure drop trend should be carefully monitored, especially after a trip incident. In addition, any wetting incident can reduce the strength of catalyst pellets, which could contribute to a high pressure drop. Any inappropriate or inadequate hold-down layer on top can also cause high pressure drop issues.

Mass balance across the shift reactor. Assume there is an HTS reactor in the flowsheet and that mass balance will need to be calculated.

Case 1. The inlet temperature is 320°C, and the outlet temperature is 394°C. The outlet composition (dry basis) reported by the laboratory was the following:

- H_2 = 74.86 %
- CH_4 = 4.16%
- CO = 3.38%
- CO_2 = 16.36%
- N_2 = 1.23%.

TABLE 8 shows the inlet and outlet compositions after doing *C* and *O* balances. At the end of the shift reactor, 3,038.25 kmol/hr of H_2 is produced in Case 1. Using Eqs. 26 and 27, the WGS approach can be calculated as:

$$Kp\ (WGS) = [([H_2][CO_2])/([H_2O][CO])] \quad (26)$$

$$\text{Ln}\ (K_p\ WGS) = 0.63508Z^3 - 0.29353Z^2 + 4.1778Z + 0.31688 \quad (27)$$

Eqs. 26 and 27 are used to calculate the following:

- $K_{p(WGS)}$ = 10.2 and $T_{eq\ (WGS)}$ = 403.2°C
- WGS approach = $T_{eq\ (WGS)} - T = 403 - 394 = 9.2$°C.

Case 2: The naphtha case. In this case, the inlet temperature is 320°C, and the outlet temperature is 396°C. The outlet composition (dry basis) reported by the laboratory was the following:

- H_2 = 71.96 %
- CH_4 = 2.46%
- CO = 3.2%
- CO_2 = 22.37%.

TABLE 9 shows the inlet and outlet compositions after doing *C* and *O* balances. At the end of the shift reactor, 1,147.25 kmol/hr of H_2 is produced in Case 2. The temperatures and WGS approach are the following:

- $K_{p(WGS)}$ = 10.8 and $T_{eq\ (WGS)}$ = 397.1°C
- WGS approach = $T_{eq\ (WGS)} - T = 397.1 - 396 = 1.1$°C.

PSA section. Generally, H_2 recovery across the PSA is 85%–90%. Assuming 87% H_2 is recovered across the PSA, the H_2 production in Case 1 would be 3,038.25 × 0.87 = 2,643.3 kmol/hr. In Case 2, it would be 1,147.25 × 0.87 = 998.1 kmol/hr. This needs to be cross-checked with the PSA purge gas flow and the H_2 content.

Takeaway. There is no denying that proper checks and balances in the plant are crucial for ensuring maximum operational efficiency—and that mass balance is one of those crucial checks. The primary objective of this practice-oriented article is to ensure that the process engineer understands the significance of KPIs across each section of the plant and is confident in doing calculations (e.g., approaches to equilibrium), using available plant and lab information. By following the monitoring aspects highlighted in this article, the process engineer will be in a better position to make sound technical judgments when doing a technical bid and/or routine plant evaluations. HP

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Impact of inaccurate water-in-oil measurement

Water-in-oil content is an important parameter for both the upstream and downstream sectors of the oil and gas industry. Water is co-produced during oil and gas production as a byproduct, and as oilfields mature, water production often increases as a result of water injection for reservoir pressure maintenance. The increasing presence of water in production fluids can lead to process capacity issues, which affect oil/gas/water multiphase separation and, consequently, the quality of oil and gas for export. The presence of water in an export crude oil and/or gas can not only impact the sales value, but also lead to operational issues such as pipeline corrosion or hydrate formation, as well as problems in downstream refining and refinery operations.

For the upstream oil and gas industry, water-in-oil content is also referred to as water cut and is included in multi-phase flow measurement for production monitoring, allocation and well testing operations. Knowledge of the proportions of oil, gas and water from individual wells helps to maximize the production rate and, ultimately, the overall recovery of the oil and gas from a particular field.

For custody transfer and/or allocation, water-in-oil content must be determined accurately and discounted, as it is not a commodity. Here, water-in-oil is usually low and is measured as part of basic sediment and water (BS&W), a key quality parameter in custody transfer and crude oil sales.

Accurate measurement of water-in-oil is therefore essential for the oil and gas industry, both upstream and downstream. Inaccurate measurement could lead to production process problems, transportation issues, pipeline integrity concerns and loss of revenue from the sales of commodity oil and/or gas, as well as refinery operations problems.

Measurement of water-in-oil can be carried out by sampling and subsequent laboratory analysis using standard methods. It can also be achieved using online water-in-oil measurement devices—at least four techniques are known to have been commonly used and are discussed here.

Production, allocation, transportation and custody transfer. In oil and gas production, well fluids containing a mixture of oil, gas, water and solids are brought to the surface where production separators are used to separate the mixture into gas, oil and water and solids phases. The gas separated is then compressed, dehydrated and exported (or flared, as an option), while separated oil is sent for export. Solids accumulated inside the separator are periodically removed, cleaned and discharged—if this is permitted—in an offshore environment. Separated water then goes through a treatment process where oil and solid contaminants are removed. The cleaned water is then either discharged for disposal, re-injected for reservoir pressure maintenance, or re-used for agriculture, irrigation or hydraulic fracturing operations purposes.

Production fluids can come from wells in the same oil and gas field, but they can also come from different fields owned by separate operating companies. Therefore, well testing using a test separator, as shown in FIG. 1, is periodically carried out to establish the rate of oil, gas and water produced by the individual wells. Knowledge of the rate and proportions of various phases in the individual wells allows for the overall production to be optimized. In cases where well fluids from different operating companies are processed, it is essential that the total rate of oil, water and gas are correctly calculated and "allocated" back to the individual wells and their owners to ensure each obtains a fair share of the production fluids. Allocation is a process rooted in the need to distribute the

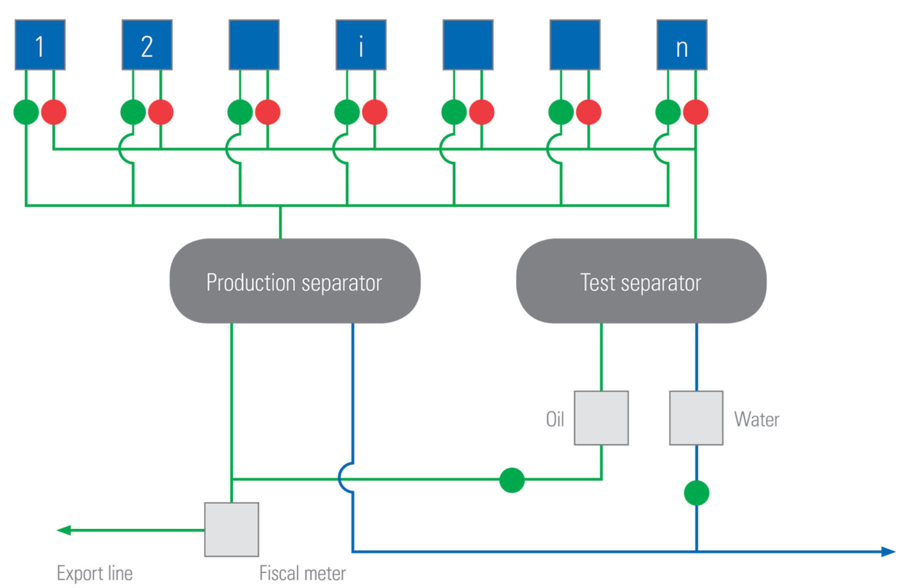

FIG. 1. Schematic of production and well test arrangement.

costs, revenues and taxes among multiple players collaborating on field development and the production of oil and gas.

When a well test is carried out, water-in-oil or water cut is measured for the oil stream exiting the separator oil outlet. Together with the rate of the water stream, the total water production rate from a specific well can be calculated. With the advancement of multi-phase flow measurement technologies, well testing is increasingly carried out using a multi-phase flow measurement device, which can measure the amount of water, oil and gas simultaneously without the use of a test separator.

When oil and/or gas are exported, a pipeline is commonly used. Due to the density difference between water and oil, and between water and gas, water-in-oil or water-in-gas can drop out and accumulate within certain parts of the pipeline, which can then lead to corrosion problems (**FIG. 2**). The presence of water-in-gas during transportation can also potentially lead to the formation of gas hydrate within the pipeline under certain temperature and pressure conditions. Gas hydrate is essentially ice that contains natural gas that, when present, can potentially lead to a pipeline blockage, resulting in operational and safety issues. Knowledge of the level of water-in-oil or water moisture in gas can help determine the likelihood of corrosion taking place and/or gas hydrate formation inside the pipeline. It can also help determine the level of anti-

FIG. 2. Accurate measurement of oil-in-water reduces the likelihood of pipeline corrosion formation.

hydrate formation chemicals that may be required to prevent gas hydrate formation or the scheduling of the pipeline inspection and maintenance regime.

The terms "custody transfer" and "fiscal metering" are often used interchangeably. They refer to the transactions involving transporting oil and gas commodities from one operator (or owner) to another and includes the transferring of oil and gas between tanks and tankers, tankers and ships, and other transactions. Custody transfer in oil and gas measurement is defined as a metering point (location) where oil or gas is being measured for sale from one party to another. For fiscal metering or custody transfer, water-in-oil must be measured accurately and then discounted.

Crude oil BS&W and refineries.

Crude oil received in a refinery usually contains water, salts, clay and sand, which are generally included in the water-in-oil or BS&W measurement. Salts present include those of magnesium, sodium and alkaline earth metals and are generally dissolved in the water component of the crude. These components are unwanted by refineries, as they can cause problems to operations that include:

- Salt water can lead to corrosion of piping and process equipment.
- Sand, salt and clay particles can cause serious erosion or damage to pumps and pipelines. They can also lead to deposits and foul heat exchangers and cause blockages.
- Salts can poison the catalyst used in crude oil refining processes.

To avoid their potential impact on operations, BS&W components must be removed before the crude oil undergoes refining. Fresh water is often added to wash the crude oil, which then goes to a desalter where the wash water is separated, collected and treated before discharging.

In Europe, according to a June 2020 Concawe report,[1] "2016 survey of effluent quality and water use at European refineries," of the 72 refineries in Europe that responded to the survey, 2.46% of the total fresh water used (352 MMm^3, excluding the once-through cooling water) was for desalting. This is compared to the total treated effluent water of 330 MMm^3 reported in 2016.

From a refinery standpoint, knowing the level of BS&W in the incoming crude oil is important, as it will determine the amount of freshwater required for the desalting process, and the subsequent effluent water treatment process.

Measurement methods and technologies.

Water-in-oil can be measured using online technologies, as well as laboratory standard methods. Online technologies are increasingly used for fiscal, custody transfer and process operations, in particular, after the publication of the American Petroleum Institute (API) MPMS TR 2570 / EI HM56 technical report, "Continuous online measurements of water content in petroleum (Crude oil and condensate)" in 2010.[2] These online instruments offer many benefits in terms of cost savings, real-time continuous water-in-oil information and increased productivity. Laboratory standard methods are also important and have been traditionally used to measure water-in-oil concentration and to calibrate and validate the performance of online water-in-oil measurement devices.

Laboratory standard methods. For fiscal, custody transfer and allocation, laboratory-based water-in-oil concentration measurement standard methods have played, and will continue to play, an important role. They are well-established and have been practiced by the oil and gas industry for decades. Many standard methods are available, including centrifuge-based, distillation-based and Karl Fischer titration-based.

All Karl Fischer methods are generally better and more accurate than distillation and centrifuge-based water-in-oil analysis methods. In general, the coulometric Karl Fischer method is better and more accurate than the volumetric Karl Fischer method. However, Karl Fischer titration-based methods are affected by the presence of mercaptan and sulfide (S- or H_2S). Also, Karl Fischer titration methods require the use of expensive, hazardous chemical reagents and delicate glass pieces, and the reagents must be replenished continuously. In addition, routine cleaning of the laboratory equipment parts is labor-intensive and time-consuming.

Online water-in-oil measurement. Most commercially available online water-in-oil measurement instruments are designed and constructed based on four techniques: capacitance, density, infrared absorption and microwave (**FIG. 3**).

Capacitance-based technology prob-

ably has the longest commercial history. It is a simple, well-proven, low-cost technology. As a method, it works well when the oil is the continuous phase and it is also relatively insensitive to water salinity. Most of the systems on the market at present can measure low percentages of water-in-oil accurately.

Density-based water-in-oil measurement technologies may include Coriolis, gamma-ray or x-ray, and are popular for multi-phase flow measurement. While they can provide additional information, such as flow, viscosity and density in the case of Coriolis meters, these systems are generally affected by the presence of gas bubbles and solid particles. They are also sensitive to variations in process conditions. Overall, density-based systems present significant uncertainty when measuring lower level water-in-oil concentration.

Infrared absorption-based technology covers the entire water-in-oil measurement range. Although it is also unaffected by changes in density, salinity or entrained gas, it is not particularly accurate at a lower water-in-oil concentration range. Microwave-based technology is more accurate for lower water-in-oil concentration range applications; however, its high initial cost and sensitivity to salinity must be considered, despite its robustness.

Operational, safety, financial and environmental impact. For fiscal or custody transfer, inaccurate measurement of water-in-oil will directly impact revenue. For example, oil tankers can typically transport between 500,000 bbl and 4 MMbbl of crude oil. For a tanker with a capacity of 1 MMbbl of oil, a water-in-oil content of 0.5% means that as much as 5,000 bbl of water could be present in the tanker. At $70/bbl of oil, this means a potential financial exposure of $350,000.

Around the world, some 90 MMbpd of crude oil are produced globally—in pipeline transportation and allocation, water-in-oil content can be much higher than 0.5%. Thus, any inaccurate water-in-oil measurement can have a significant impact financially to all the parties involved (i.e., production partners, oil and gas commodity sellers and buyers).

For oil and gas transportation using pipelines, pipeline integrity is paramount for operators. Corrosion-related pipeline incidents can lead to catastrophic consequences. For example, in 2000, the Carlsbad Pipeline explosion in New Mexico that killed 12 people was caused by internal corrosion to a 30-in. natural gas pipeline. Also, the 2006 Prudhoe Bay Oil Spill in Alaska, in which some 267,000 gal of crude oil leaked from the pipeline, was linked to corrosion. By accurately

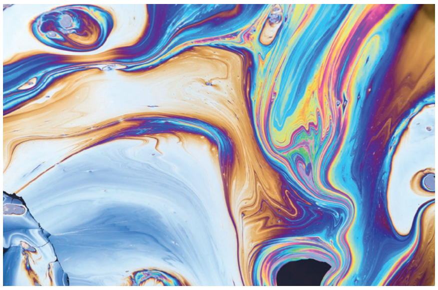

FIG. 3. Most commercially available online water-in-oil measurement instruments are designed and constructed based on four techniques: capacitance, density, infrared absorption and microwave.

measuring water-in-oil (or condensate) and moisture in gas and ensuring that the concentration is within the specification set by the pipeline operators, the risk of water-led corrosion is reduced, minimizing the risk of corrosion-induced pipeline leakage or rupture.

For oil and gas production, inaccurate water-in-oil measurement could lead to a sub-optimized process and a reduced production rate. Wells that produce fluids containing a large amount of produced water may be choked back and even shut in to allow more to be produced from those that contain less water. For production optimization, it is also important to measure the water content in the separator oil outlet for process control purposes. Accurate measurement at this point would provide the information required for the correct dosing of production chemicals, such as demulsifier and defoamant, to assist the multi-phase separation. It would also enable the correct setting of the oil and water interface level inside the multi-phase separator for optimized operation, as well as ensure that the water content level in the oil is within the export quality specification.

Inaccurate water-in-oil measurement can also affect the performance of produced water treatment systems or refinery wastewater treatment systems, which then impact the quality of treated water for discharge. The discharge of produced water or refinery wastewater is strictly regulated.

Trends and needs in water-in-oil measurements. Traditionally, water-in-oil determination in custody transfer and allocation has been carried out by sampling and laboratory analysis, a laborious and time-consuming process. Online continuous water-in-oil measurement provides real-time determination of water in a flowing hydrocarbon stream. It offers many advantages, and can potentially improve system efficiency, operational safety and help to streamline system operations if reliable and accurate. The API has an active working group developing a standard for online measurement of water content in petroleum and petroleum productions, which is a clear indication of the importance of the subject to the industry.

Online continuous water-in-oil measurement devices have been available on the market for a long time. However, few studies have been conducted in which these online water-cut measurement devices are tested and evaluated independently and in a collective manner. The only known tests were conducted back in the 1990s, in which commercially available devices were tested using a specially designed and developed flow loop. Since then, measurement technologies have advanced and been improved, and new instruments have also been developed; therefore, a need exists to test and evaluate such devices again.

In 2019, Pipeline Research Council International (PRCI) commissioned such a project. In the project, a closed-loop performance test was planned to measure the error between known water content and the water content measured by the different water cut meter technologies. The tests would cover water-in-oil content range for both custody transfer and allocation/process applications. Results obtained from the project were to be shared by PRCI members and were also expected to provide input into the API standard development. It is understood that the project has now been completed; however, no results have been publicized to date.

There also seems to be a technology gap in online measurement of very low water content in gas condensate or crude oil applications in the parts per million (ppm) range. For gas and gas condensate production, separated gas and condensate streams are often recombined and exported. Thus, water content in condensate oil will affect the overall water moisture level in the gas/condensate export line. In the U.S., the accepted maximum water presence in gas is 7 lb/MMsft^3 (147 ppm), while in Canada, it is 4 lb/MMsft^3 (84 ppm). Both capacitance and microwave-based technologies have been explored for ppm range of water-in-condensate applications, but there has been limited success.

Takeaway. Measurement of water-in-oil is crucially important for the oil and gas industry in relation to fiscal or custody transfer, production and production allocation, pipeline transportation and refinery operations. Inaccurate water-in-oil measurement can directly and indirectly impact operators' finance, production operations, pipeline integrity and safety, refinery operations and the environment.

For custody transfer and allocation, measurement is often carried out by sampling and laboratory analysis, for which standard measurement methods based on using centrifuge, distillation or Karl Fischer are available. However, an increasing demand exists for online measurement devices for which the oil and gas industry continues to work together to create standard practices and guidelines.

For oil and gas production operations, online water-in-oil devices are already widely used as part of multi-phase flow measurement. Most water-in-oil devices use one of four measurement technologies: capacitance, density, infrared absorption or microwave. For online water-in-oil measurement, independent tests are needed to evaluate instruments available on the market. There also seems to be a technology gap in accurately measuring the ppm range of water-in-condensate oil for gas and gas condensate production and pipeline transportation applications.

For crude oil refinery operations, water-in-oil and/or BS&W in general is unwanted and requires removal. This is done by the desalting process in which fresh water is added and then separated. Accurate measurement of water-in-crude oil impacts freshwater consumption and subsequent effluent water treatment processes. HP

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Advanced methods for controlling boiler tube corrosion and fouling—Part 2

In Part 1 of this article, the authors covered techniques for minimizing corrosion and contaminant ingress from condensate return and feedwater to industrial steam generators. While some corrosion mechanisms can cause severe damage to condensate and feedwater piping, heat exchangers and other equipment, the release of corrosion products or the transport of other impurities to the boilers can also cause major problems. This article examines internal boiler treatment programs, which include several critical functions, including:

- pH control within a mildly alkaline range to minimize general corrosion
- Reaction with impurities to keep contaminants in suspension and minimize deposition on boiler internals.

As suggested in Part 1, even well-treated boilers may have chemistry underneath existing deposits that varies greatly from the bulk boiler water, and severe corrosion under these deposits may lead to tube failures and unit outages. This article includes a direct example of this scenario.

Internal boiler water treatment. As power generation units increased in number and size in the 1930s, tri-sodium phosphate (Na_3PO_4, or TSP) became a popular water conditioning chemical for drum boilers. At that time, phosphate treatment served two primary functions. The first was to establish moderately alkaline conditions in the boiler to minimize general corrosion of carbon steel boiler tubes, drums and headers (Eq. 1):

$$Na_3PO_4 + H_2O \leftrightarrow Na_2HPO_4 + NaOH \quad (1)$$

This function is still critical today.

The second function of phosphate was—and in some cases, still is, for industrial boilers—control of hardness ingress. Phosphate will react with hardness to form soft sludges that may be blown down, as opposed to the hard scale shown in **FIG. 11** of Part 1. However, as high-pressure units evolved in the last century, some boilers were plagued by under-deposit caustic corrosion generated by the rather high concentrations of TSP needed for scale control. This led to the development of coordinated and congruent phosphate treatment programs that were often a blend of tri- and di-sodium phosphate (DSP), but sometimes included a small amount of monosodium phosphate (MSP). DSP and MSP will shift Eq. 1 to the left and reduce the NaOH concentration.

The development of congruent treatment was also influenced by the discovery that sodium phosphates become reversely soluble at temperatures above approximately 250°F (**FIG. 13**).

In high-pressure boilers, most of the phosphate added for pH and, if necessary, hardness control may precipitate on boiler internals. This precipitation, known as "hideout," is accentuated by boiler tube deposits. Congruent treatment was developed to maintain similar sodium-to-phosphate ratios between the chemical remaining in solution with that in precipitate, although this often does not occur.

Even so, phosphate treatment remains a strong choice for industrial boilers, particularly because the potential for hardness ingress to many industrial units is much greater than for utility units. TSP is now the only phosphate species recommended for power boilers and is applied at low concentrations to minimize hideout. Industrial boiler treatment should be evaluated on a case-by-case basis. If heavy deposits are present, then chemistry control may "run on the razor's edge," so to speak. If only TSP is used, then excess hydroxide could potentially concentrate under the deposits and generate caustic attack. Conversely, under a congruent program, acid phosphate compounds might form and attack the tube metal.

As the following example illustrates, significant improve-

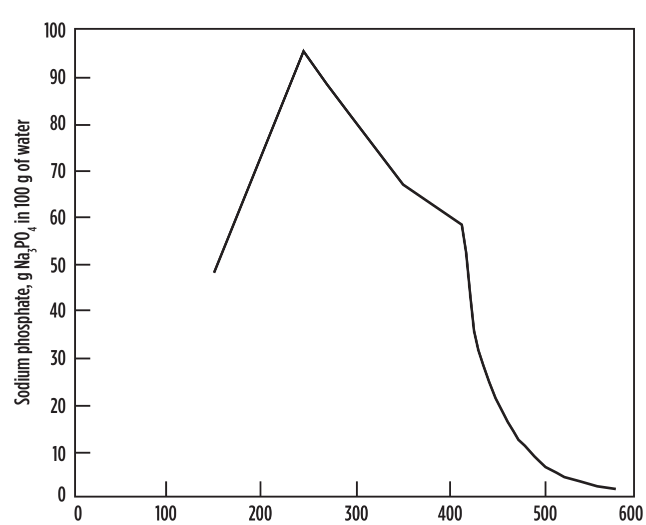

FIG. 13. Solubility of tri-sodium phosphate as a function of temperature.

ments are often possible if dispersion polymers are added to boiler water treatment formulations. This example also highlights the difficulties with localized hot spots that often exist in specialized steam generators. Such locations can accentuate deposition and under-deposit corrosion.

Specialty boiler influence on corrosion. Certain unit processes produce waste heat or high-temperature product gas that is utilized for steam generation. Examples include syngas from ammonia production, the offgas of steel and annealing furnaces, cement kiln flue gas, etc. Waste heat boiler design is often unique and may include localized high heat transfer zones. These features can significantly influence corrosion issues and boiler water treatment.

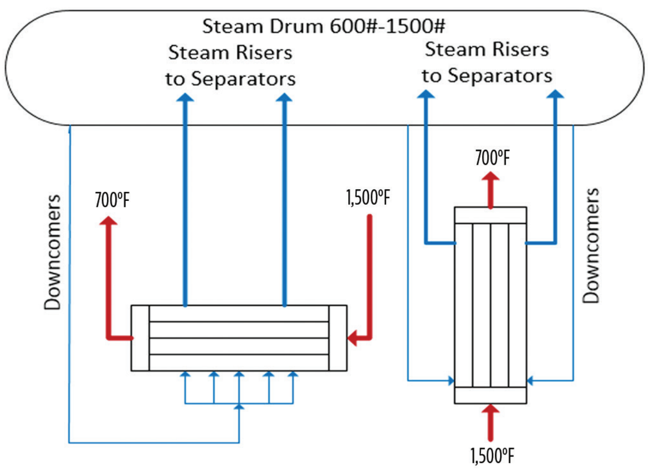

FIG. 14. Basic flow diagrams of horizontal and vertical TLEs. Primary TLEs are heated with pyrolysis gas. Some systems may also have secondary TLEs heated with the partially cooled gas from the primary TLEs.

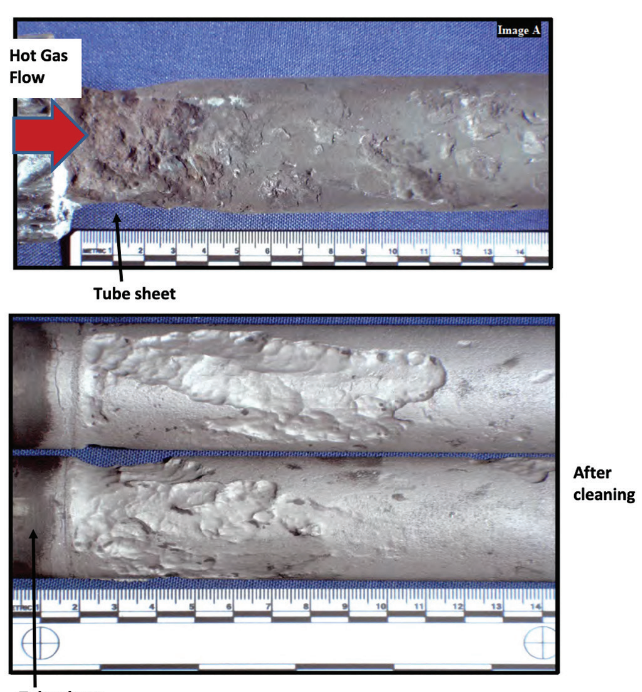

FIG. 15. Localized corrosion in a high heat flux zone of a TLE.

A prime example from the refining industry is pyrolysis effluent gas from cracking furnaces, which is quickly cooled in transfer line exchangers (TLEs). Normally associated with ethylene production, TLEs also can be found in petrochemical industries that produce syngas from methane steam reformation, such as methanol, acetic acid, formaldehyde and others. The TLE cools the pyrolysis gas to prevent further hydrocarbon cracking, generating steam for other unit operations in the process.

A TLE is similar to a fire-tube boiler, with the cracked gas stream on the tube side and water on the shell side. The design incorporates a steam drum and operates under natural, thermally induced boiler water circulation. Many different designs are available from various manufacturers, and the design geometry can be either horizontal or vertical (**FIG. 14**).

In many configurations, several TLEs are attached to a common steam drum. The boiler water from the steam drum flows through downcomers to several TLEs in a natural circulation arrangement, with the resulting steam/water mixture returning to the steam drum via riser tubes. Temperature-resistant materials are often used for ferrule inserts on the inlet of the hot gas path to protect the thicker tubesheets, which are also coated with refractory. Horizontal TLEs may include individual blowdown lines that tie into the common continuous blowdown from the steam drum. These boilers offer a classic example of problems that can occur in localized high heat flux zones (**FIG. 15**).

The authors' company has investigated numerous TLE tube failures with visible metal wastage that occurred just inside the tube sheet and under deposits. Corrosion evaluation requires detailed metallurgical analyses, as some mechanisms, most notably acid phosphate corrosion and caustic attack, have similar morphologies even though they are far apart on the pH spectrum. The bulk water chemistry may be satisfactory, but heavy deposits on the tube surface can still initiate and perpetuate corrosion.

Three primary areas of focus exist for facilities looking to alleviate such problems:

1. Maintaining consistent feedwater purity
2. Establishing an internal boiler water treatment program with reduced phosphate concentrations to minimize hideout
3. Selecting effective polymers to aid in the dispersion of iron (and copper, where applicable) corrosion products transported from elsewhere.

A dispersion polymer is recommended in all TLEs or similar waste heat boilers. However, the thermal stability of dispersion polymers becomes very challenging as pressures exceed 1,200 psi. Blended phosphate/polymer products perform well up to approximately 1,800 psi; other blends are available that function at even higher pressures. However, the proper choice can be made only after a thorough evaluation of system operating conditions (with pressure being a prime factor), metallurgy, feedwater quality and other factors. Polymer supplements are not a ticket for operating outside of American Society of Mechanical Engineers (ASME) guidelines, however. Regardless of chemical treatment, hardness, for example, can be very problematic in high-pressure boilers. **Note:** A revision to the existing ASME boiler guidelines is being finalized, and it may be released this year.

Notes on steam system protection. This two-part article series focused on methods for minimizing corrosion and de-

position within the condensate/feedwater systems and boilers of steam generating systems. While these issues are extremely important, protecting the steam system may be even more critical, particularly if the steam powers turbines. Steam turbines are highly tuned mechanical devices that are extremely expensive to repair or replace after mechanical or chemical failure, and may hobble a plant for months, if not longer.

Additionally, solids carryover into steam can induce deposition and corrosion in superheaters, which may cause heat exchanger failure even in industrial steam generators without turbines.[2] Depending on unit pressure, some steam chemistry guidelines call for impurity limits at low parts-per-billion (ppb) levels. Steam chemistry control is, therefore, an integral part of any steam generator chemistry program.

Takeaway. A summary of key principles for internal boiler water treatment and corrosion/scale control follows:

- Careful selection of an internal boiler water treatment program is recommended. The choice of phosphate treatment often depends greatly on makeup quality. Maintaining low phosphate concentrations is now common practice for avoiding hideout.
- Dispersion polymers can be effective up to approximately 1,800 psi to sequester metals transported to boilers. These contaminants can be removed via blowdown. Minimizing iron and copper deposition will help reduce the risk of under-deposit corrosion.
- Proper boiler water chemistry control is also critical for preventing carryover and other impurity ingress to steam. Some contaminants can cause major damage, particularly if the steam drives turbines for electrical or mechanical output.[3]
- The importance of monitoring cannot be overstated. Upsets have been known to cause boiler tube failures within days, sometimes even hours. Continuous online instruments are available for complete steam generation chemistry monitoring. Intelligent water management software is available for tracking and analyzing data and providing reports and alarm notices to plant personnel. This program is also well suited for monitoring other plant water systems, including cooling water.

Each system is different and has unique treatment needs, and due diligence is necessary for determining the feasibility for utilizing these methods. Equipment manuals and guides should always be consulted, and a water treatment professional contacted, before changes are made to systems and treatment processes. HP

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Integrate artificial intelligence with natural intelligence

Have you noticed that many articles about artificial intelligence (AI), machine learning, data analytics, the Internet of Things (IoT) or digital transformation likely include an image of a human brain, like the one shown in **FIG. 1?** For many years, the technology field has been borrowing human anatomy concepts such as deep learning, an algorithm to recognize patterns using neural networks. Publishers, editors and journalists would advise me about the old cliché of "burying the lead," but note the next few paragraphs about genetic engineering before shifting our focus to industrial engineering.

An article in *The New York Times* by Pagan Kennedy, "What if you knew Alzheimer's was coming for you?"[1] highlighted that simple blood tests may be able to deliver alarming news about one's cognitive health. "Scientists say they are on the cusp of developing blood tests that could detect the earliest signs of Alzheimer's damage in people in their 40s and 50s who have no obvious symptoms," the article states. "Today, finding out whether dangerous plaques are building up in your brain requires either a PET (positron emission tomography) scan at a cost of about $4,000, or a spinal tap. And while genetic tests can help predict risk, they don't tell us anything about the current states of your brain."

FIG. 1. The technology field has been borrowing human anatomy concepts, such as deep learning, an algorithm to recognize patterns using neural networks.

Despite the scientific progress, this creates a social barrier: Do you really want to know about your complete mental state and share it with others? Do you want to keep it private from employers and health insurers, or do you want to "openly embrace it as part of your identity and publicly advocate for a cure?" The dilemma affects many health organizations to the extent that some discourage patients from learning their ApoE genotype (**FIG. 2**). Some doctors cannot justify any drug or lifestyle strategy that absolutely guarantees to protect the brain. The U.S. Food and Drug Administration's (FDA's) approval of a proprietary monoclonal antibody[a] may renew interest in further research despite past failures.

Parallels to industrial assets. When compared to the world of industrial assets, the brain can be paralleled to any central piece of equipment, machinery or control system with high criticality. Is there a single industrial measurement analogous to identifying the ApoE4 gene[2] that can indicate the health of the asset? Very likely, a larger set of parameters (the "genotype") of the physical asset must be examined in real time (the present) to draw potential conclusions. More can be understood if historical data (the past) associated with those parameters are readily available for a diagnostic analysis.

An additional valuable step is to use the right data to predict likely outcomes (the future). Combining the present, the past and the future, some mechanism of "intelligence" can be applied to perform descriptive analytics (what has happened to the asset health), diagnostic analytics (why the asset health has gone through a certain condition), predictive analytics (when and what may happen to its health) and prescriptive analytics (actionable insights of what should be done).

Like the human body, a manufacturing facility, industrial plant or an operational unit is a set of interconnected assets (organs) functioning according to the laws of physics, conserving mass, energy and momentum under constraints of safety, environment, sustainability and economics. To assess the overall health of the production asset, an experienced operator will check several critical variables in a holistic fashion, identifying simple pump cavitation the same way a doctor would pay attention to the heart and lungs working together in equilibrium. In the same manner a physician would order a blood exam for an elderly patient to check the leukocytes level for possible infection (as high temperature or fever is usually absent despite bacterial or viral contagion), an operator will check the laboratory

assay of the recently arrived crude oil to correlate to the new heat exchanger fouling development.

A field operator will walk through the plant listening for possible problems, such as a compressor with a knocking noise, looking at steam traps releasing live steam rather than flash steam, or checking lube oil leakage around motors and pumps. The operator wears personal protective equipment (PPE) along with a portable gas detector and performs an inspection of the vibration in rotating machinery or a quick boiler flame inspection using a pyrometer. Since most of these sensors are available today with wireless connectivity, the need for walkarounds is minimized. Similarly, a nurse will wear a mask to avoid contamination while checking temperature, auscultating heart and lungs with the appropriate devices.

The striking difference between the scientific progress in testing the ApoE genotype and checking the health of a physical asset is that some human patients do not wish to undergo the genetic exam or know its result, while industrial "patients" want to know about their condition as soon as possible. Plant operators want to be proactive in avoiding the next unplanned downtime. Manufacturers are eager to use all available data to predict future failures and to prescribe action to avoid any production loss, personal accident or environmental incident. There is no "social barrier" in disclosing the health condition in an industrial facility. It is exactly the opposite: insurance companies are heavily investing in the IoT to reduce costs in the long term, and share the savings with their customers.

However, huge potential exists for breaking through the "social barrier" of harvesting the scientific evolution from Isaac Newton and Antoine Lavoisier's times to the current era of machine learning and AI. A polymerization reactor, a steel mill blast furnace or a wood pulp digestor can be mathematically modeled at the microscopic level using the Navier-Stokes partial differential equations, which perform mass and energy balances combined with kinetics mechanisms and integrated to the boundary conditions of real-life operations. In the realm of reliability engineering, there are more than 20 probability distributions estimating failure rates along with time, including the popular Weibull distribution. Statistics have been used heavily in the analytics marketing field not only to predict customer behavior (when the next purchase will take place), but also to predict asset performance using machine-learning techniques such as neural networks, multilayer perceptron (MLP), radial basis functions, support vector machines (SVMs), Naïve Bayes, k-nearest neighbors and geospatial predictive modeling.

With so much algorithmic and computational power available today, some practitioners just want to throw more data to machines to unravel correlations to predict future behavior. Meanwhile, they are not taking advantage of the universal library of scientific knowledge that has been built through human evolution. They rely too much on data and intelligent machines to almost completely replace the operational experience acquired in starting new plants, revamping old units, undergoing a multi-year turnaround, or facing the pressure of recovering from an unplanned downtime in a sold-out economic scenario. Instances have been seen of AI turning day-to-day operations into a zero-sum journey to the detriment of natural intelligence (NI).

Often, the human element is being minimized throughout the experience. A computer can be trained to play chess and it

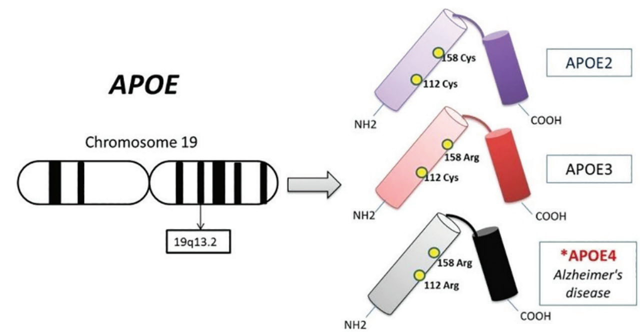

FIG. 2. ApoE derives from the protein Apolipoprotein E.[2]

FIG. 3. Passengers on US Airways Flight 1549 await rescue after a successful emergency landing on the Hudson River.

will end up beating a human player. However, it does not know how to play checkers, and it will be beaten by a human competitor. It must be trained how to play checkers. What if another computer, machine or robot teaches it how to play checkers? This may lead to a machine training another machine how to identify an issue with a fluid catalytic cracker in an oil refinery and zooming into the root cause being its aging catalyst without consulting a human subject matter expert (SME) and confirming the diagnosis. This is a matter of leaving money on the table by failing to integrate AI with NI.

Miracle on the Hudson. On January 15, 2009, US Airways Flight 1549 (Airbus A320-214) struck a flock of Canadian geese and lost all engine power two minutes after takeoff from New York City's LaGuardia Airport. Unable to reach any airport, pilots Chesley "Sully" Sullenberger and Jeffrey Skiles glided the plane to a water landing in the Hudson River off Midtown Manhattan (**FIG. 3**). The incident came to be known as the "Miracle on the Hudson."

Upon colliding with the geese, both of the aircraft's GE Aviation/Snecma-designed CFM56 turbofans were damaged and the associated electrical controls malfunctioned. Immediately after the bird strike, according to the National Transportation Safety Board (NTSB),[3] Captain Sullenberger accomplished a critical item that the flight crew did not reach in the checklist: starting the Honeywell Auxiliary Power Unit (APU), a small gas turbine engine that provides electrical power for starting an aircraft's main engines and running air conditioning and other systems while the plane is on the ground. According to the NTSB report, "Starting the APU early in the accident sequence proved to be critical because it improved the outcome of the ditching by ensuring that electrical power was available to the airplane" during the 58-sec elapsed time.

The data reported by the Aircraft Communications Addressing and Reporting System (ACARS) satellite communications system indicated that the left engine was still running. Theoretically, this would have left the pilots with enough power to return to LaGuardia or land at another airport nearby. Captain Sullenberger, however, sensed from his experience that he had lost both engines, which left him without sufficient time, speed or altitude to land safely at any airport. The result is well-known: by keeping one eye on the LCD navigation display and the other on the Hudson River, Captain Sullenberger preserved all 155 lives due to his natural intelligence—despite the available data.

Takeaway. AI is augmented by embracing NI, and vice-versa. Nonetheless, the question remains: how to leverage all scientific and technological progress achieved by humankind up to now? We can begin by inviting SMEs from all fields—from engineers to statisticians to IT analysts, and including biologists, psychologists and neuroscientists—to focus on the opportunity at hand. Diversity is the keyword here. Cognitive health is linked to cognitive computing, elementary. AI can impel collaboration among people, between customers and suppliers, and between manufacturing companies and their partners.

No single corporation can cover the whole gamut of expertise required to address the process, from the genesis of data sensing to its transmission from an edge device to a cloud platform in a cyber secure way, to running digital twins that execute descriptive, diagnostic, predictive and prescriptive analytics. The end goal is solving a customer problem, addressing an operational issue with an asset, or a complete industrial facility providing business outcomes in a sustainable fashion.

If you are considering embarking or have already hopped on a digital transformation journey, a pragmatic recommendation is to integrate data and algorithmic technology (AI) with industrial operations domain expertise (NI). HP

NOTES

[a] Biogen's aducanumab

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Control valve design challenges for green diesel processes

Green (or renewable) diesel is a biofuel that offers several advantages over biodiesel, so many refineries are increasingly including it in their production portfolios. The downstream portion of the refining process is very similar to traditional diesel hydrotreating processes, making modifications less onerous than switching to the production of a totally different fuel.

While similar, there are some process differences between green diesel and standard diesel that are more difficult to handle for the critical control valves in the unit. This article discusses the green diesel process, and it offers suggestions for choosing the best valves for reliable, safe and profitable production.

Biodiesel vs. green diesel. Biodiesel has its roots from experiments conducted in the 1930s, and it has been produced in quantity since the 1980s. It uses a transesterification process to convert various vegetable oils and/or animal fats into fatty acid methyl esters (FAME). The burn characteristics of FAME are like diesel fuel, but it is chemically different and tends to gel in colder temperatures. This gelling limits the amount of FAME that can be blended to 10%–20% of the total diesel volume, and, even then, the fuel can be troublesome to handle during colder winter months.

Green diesel is a more recently introduced process that starts with the same collection of vegetable oils and/or animal fats, but the result is a product chemically identical to diesel. Since diesel and green diesel are the same in terms of end product, there is no blending restriction, and any engine can operate on 100% green diesel. FIG. 1 compares biodiesel, green diesel and regular diesel.

	Biodiesel	Renewable/Green Diesel	Diesel
Feedstock	Vegetable Oils & Animal Fats	Vegetable Oils & Animal Fats	Crude Oils
Process	Transesterification	Hydroprocessing	Hydroprocessing
Finished Product	Biodiesel (FAME)	Green Diesel, Hydrotreated Vegetable Oil (HVO), or Renewable Diesel	Diesel
Chemical Composition	O ‖ R-C-O-R'	C_nH_{2n+2}	C_nH_{2n+2}

FIG. 1. Like biodiesel, green diesel can be created from various vegetable oils and animal fats. However, unlike biodiesel, green diesel has the same chemical composition and physical properties as standard diesel and can be used as a direct replacement.

The significantly increased blending rates for green diesel enable producers to achieve much lower carbon intensity in their final product. Carbon intensity is a method of measuring how much carbon is emitted in the production and burning of a particular fuel. Gasoline, jet fuel and diesel derived from crude oil have a carbon intensity of about 100. Biofuels derived from non-crude oil feedstocks have substantially lower carbon intensity values—as low as 20, depending on the raw materials used as feedstock. The overall carbon intensity often drives regulatory credits, so the low carbon intensity and high blend rates of green diesel offer attractive incentives for refineries to switch at least some of their production.

The green diesel process. Green diesel can be created from a large variety of renewable feedstocks (FIG. 2). There is no significant advantage in production yield from one type of feedstock to the other, and each takes about 7.5 lb–8.5 lb of raw material to create a gallon of fuel.

The production of green diesel starts with pretreatment (FIG. 3). Feedstocks must be separated and treated differently to convert them into a common intermediate, which feeds the hydrotreater processing unit downstream.

The pretreatment process requires a wide variety of processing steps, with particular steps depending on the raw materials used as feedstock. The best control valves for pretreatment will vary widely (depending on the specific operations required), and selecting the proper materials of construction and alloy components will play heavily in the design effort.

Once pretreated, the green diesel intermediate is fed into the same hydrotreating process used in typical diesel production (**FIG. 4**). Green diesel processing usually produces an elevated level of corrosion due to the oxides and acids in the intermediates. Temperatures and pressures can also run higher in a green diesel hydroprocessing unit. This can create challenges for instrumentation and control valve selection.

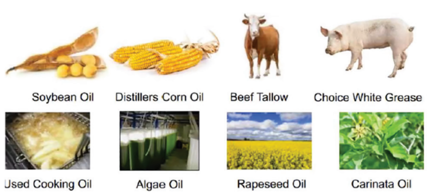

FIG. 2. A wide variety of renewable materials can be converted to green diesel. Carbon intensity values vary by product but generally favor used cooking oil and tallow. Source: Renewable Energy Group.

The temperatures, pressures and corrosive nature of green diesel production pose unique challenges for operations. Paraffin-like components also make the process more "sticky," causing control problems over time. The reactor section of the hydrotreater is the most critical unit for maximizing profitability, with reliable and tight control required for smooth operations. Poor control performance can shorten catalyst life and reduce yield, so picking the right control valves is a crucial step in the design process.

Separator letdown. One critical control element is the separator letdown control valve. This valve controls the liquid level in the high-pressure separator and passes hydrocarbons with entrained gas and particulate. Temperatures can exceed 260°C (500°F), and the valve must reduce an upstream pressure of 1,100 psi to 900 psi. The high pressure drop and very high temperature would be a challenge for any valve, but the corrosive and sticky nature of the material makes this a particularly difficult application.

A typical letdown valve would employ many very small internal passages to stage the pressure drop and handle the flashing conditions, but this type of valve would quickly plug in this service. Instead, the preferable valve design employs a multistage letdown arrangement with large flow passages to allow particulate to move through the valve. Particular proprietary high-pressure multi-stage angle valves[a] (**FIG. 5**) can be an excellent choice for this application.

These types of valves are typically offered with a variety of corrosion-resistant alloys, and they are designed to handle the very high temperatures and pressures encountered in this application. These types of valves also have large, multistage flow passages to handle the entrained solids and offgassing that are typical in this service.

The hot/high-pressure and cold/high-pressure separator letdown valves are similar applications, but within the hydrotreater unit. The best valve design in these services will often depend on the expected ratio of outgassing of the material. A very high gas volume ratio will

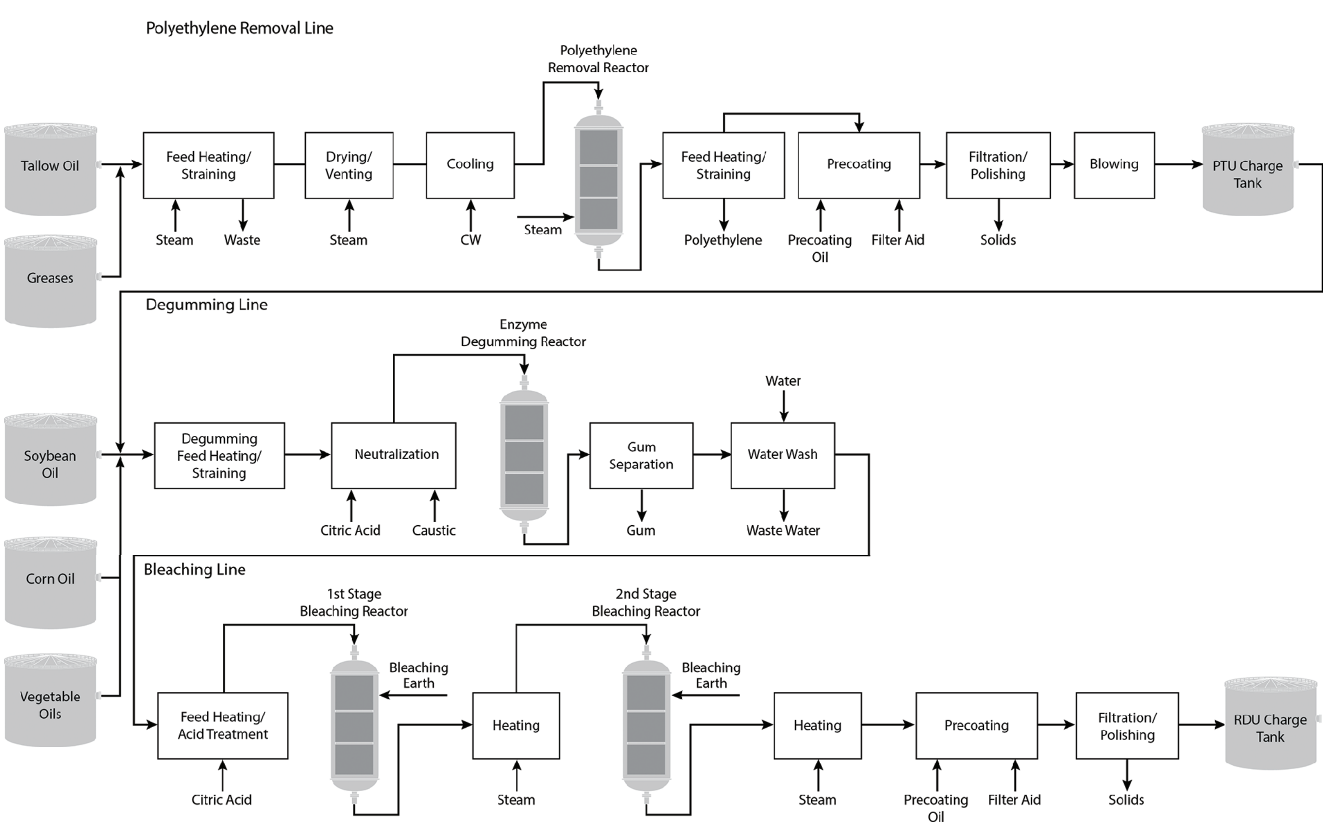

FIG. 3. Green diesel pretreatment involves different processing steps, depending on which raw material is used as a feedstock. Some combination of polyethylene removal, degumming and bleaching is usually required to convert the feedstocks into a common intermediate for further processing.

usually require a high-pressure, multistage or sweep-flow angle valve like the separator letdown.

Lower gas volume ratios may be handled with other valve designs, such as those designed for low, moderate or high gas volume ratios. Regardless of the valve designed chosen, proper alloy selection is critical for long service life.

Hydrogen quench valve. Another critical application involves the hydrogen quench control valves feeding the reactor. These valves control bed temperatures, avoid a runaway reaction and maximize catalyst life and production yield. They should provide tight control and good shutoff. Normally, valves in this service will employ a balanced plug to meet the shutoff requirements and to handle temperatures up to 232°C (450°F) with high pressures. The author's company's proprietary high-pressure globe control valves[b] (**FIG. 6**) are a good option for this service. If the quench valves are exposed to lower temperatures and pressures and there is a concern about particulate buildup, alternate post-guided control valves offer a lower cost alternative.

Pressure swing adsorption (PSA) applications. PSA units are a critical component for the entire operation (**FIG. 7**). Two (or more) adsorption beds operate in parallel, with one bed getting regenerated, while the others are online. These units typically provide very-high-purity hydrogen to the hydrotreating unit.

The PSA process typically requires many control valves, each constantly cycling open and closed as the beds are regenerated and placed online. In addition to the very high cycle counts, the valves are exposed to high temperature differentials, particulate and pressure from alternate sides. More importantly, the valves must stroke quickly and provide nearly zero leakage because slow-acting or leaking valves degrade purity and reduce production for the entire hydrotreating unit.

The best valves for this application will vary with the pressure and temperature requirements of the process. However, high-cycle, reliable, tight shutoff glove valves are often a good choice. A positioner with advanced diagnostics should be used to monitor valve stroke times and torque at closure, and to sound an alarm when a valve is falling out of specification and requires service.

Compressor anti-surge applications. The green diesel unit will usually employ one or more hydrogen compressors to pressurize hydrogen and feed it back into various points in the process. One of the most important valves on a centrifugal compressor is the anti-surge valve, which protects the machine.

During low-flow, high-discharge pressure conditions, the gas flow can instantaneously reverse through a compressor. When this occurs, the discharge pressure immediately falls and the gas flow surges forward again, repeating the cycle. Once compressor surge starts, the repetitive flow reversals can shear turbine blades, destroy bearings and take a compressor out of commission for months.

An anti-surge valve is installed on the discharge of the compressor and tied

back to the suction. If the flow through the compressor falls too low or a surge is detected, then this valve is instantly opened to establish forward flow and to take the compressor out of surge.

Surge valves must be carefully designed to respond very quickly, often moving between 0%–100% or any position in 1 sec–2 sec, while passing very high flows. Despite the very high pressure drop and temperatures, these valves must provide precise control. Reliability is paramount for this valve. If it fails to function as designed, the compressor can be destroyed in seconds, so a simple, highly robust valve design is important.

Recent advances in volume capacity allow some positioners to replace the typical combination of positioner and volume boosters that is normally found on most anti-surge valves. These same advanced positioners also offer advanced diagnostics and partial stroke testing to ensure that the anti-surge valve will work when called to action.

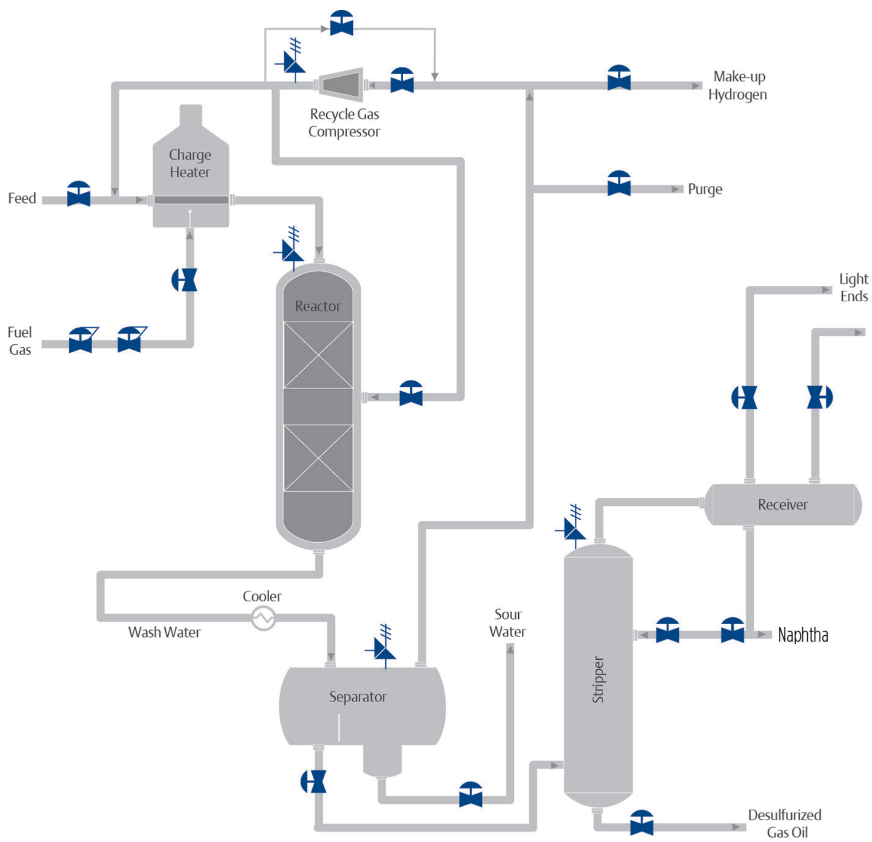

FIG. 4. The pretreated intermediate feeds a typical hydrotreating unit to produce the final green diesel product. The hydrotreating process is the same as a typical refinery but requires higher temperatures and pressures, while posing an increased risk of corrosion.

Takeaway. Green diesel shows much promise to reduce carbon intensity by replacing some of the petroleum-based diesel now being produced. Although the production process for green diesel is like that for standard diesel, green diesel does pose challenges, including proper selection of control valves and related components. Design engineers must be careful to choose the right alloys and valve designs to provide high performance and long service life.

If a refining unit is considering upgrading to green diesel production, it is important to take the time to understand the options and evaluate the various valve technologies available. New alloy offerings and new valve designs can significantly improve valve performance and service life, and consultation with your valve vendor can ensure proper selection. HP

NOTES

[a] Fisher DST-G valve

[b] Fisher HP series control valves

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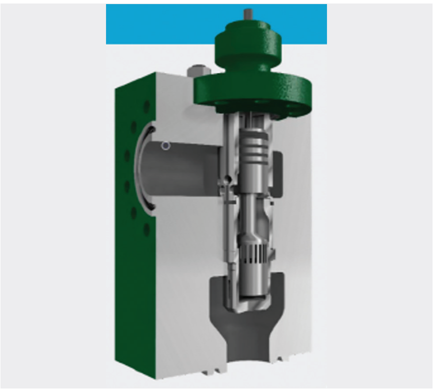

FIG. 5. Proprietary high-pressure multi-stage angle valves[a] can be a good choice for separator service in the hydrotreating process. The robust alloy construction and large, multistage flow passages allow these valves to handle very high temperatures, very high pressure drops, and the plugging nature of the material.

FIG. 6. A balanced plug with tight shutoff is usually employed in a hydrogen quench valve[b] service. Proper material selection is critical for any hydrogen service application.

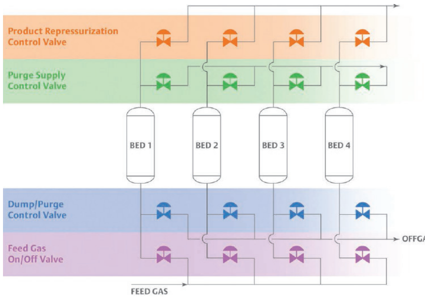

FIG. 7. The PSA process involves many control valves cycling 50,000 times/yr–200,000 times/yr. Each valve must stroke quickly and provide tight shutoff.

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Vertically suspended molten sulfur pumping challenges and best practices

The objective of this article is to share industry experience related to the reliability challenges with vertically suspended molten sulfur pumps. Due to the operating temperatures and the unique chemical properties of sulfur, several operational and reliability challenges are inherently present across the industry. The following will discuss common pump field troubles reported by operations, pump failure modes, and case studies that demonstrate typical failure modes and mechanisms.

Vertically suspended molten sulfur pumps are used in oil and gas facilities to transfer molten sulfur from melting plants. Both horizontal and vertically suspended pumps cover the broad variety of molten sulfur applications; however, this article will focus on the vertically suspended pumps.

The typical vertical design is an API VS4 or VS5 type. The VS4 is a vertically suspended, single-casing, volute, line-shaft-driven sump pump. The VS5 is the same pump design as the VS4, except that the pump is cantilevered rather than utilizing a line shaft, with intermediate bearings to support the rotor. The VS5 cantilevered design is restricted to shorter submergence depths (approximately 6 ft) and is typically applied in dirty sulfur service. By design, the cantilevered VS5 pump does not require product lubrication to intermediate bearings; therefore, this design is better suited for dirty service. **FIG. 1** shows both VS4 and VS5 pump types.

Pumping molten sulfur can be a very challenging application due to the inherently high temperatures and the unique chemical properties of sulfur. These vertically suspended pumping applications require special attention in terms of both operation and maintenance—i.e., to maintain reliability and minimize maintenance costs.

One of the most critical aspects to consider involves the unique properties of sulfur. Sulfur experiences an abnormal variation in viscosity with changes in temperature, which only allows sulfur to be pumped successfully within the range of 135°C–155°C (275°F–311°F). Most pump designs incorporate a steam-heating jacket to maintain a constant temperature throughout the entire pump. **FIG. 2** shows a typical cross-sectional drawing for an API VS4-type pump with line-shaft bearings, top anti-friction bearings and steam jacketing.

The percentage of hydrogen sulfide (H_2S) content also influences the viscosity vs. temperature characteristic, which can also change the temperature range for successful pumping. The pump material selection is also dependent on H_2S content. **FIG. 3** shows a graphical representation of sulfur viscosity vs. temperature. Due to polymerization, the liquid sulfur experiences an exponential increase in viscosity as it passes through the transitional zone of above 155°C (311°F). Typical pump-related troubles reported in the field include the following:

- Loss of flow or reduced capacity
- High vibration
- Overamping of the motor driver
- Pump seizures or broken shaft
- Corrosion issues.

These reported field troubles or failure modes can have many different causes. Each reported field trouble is discussed in the following sections, with the possible failure mechanisms. Case examples are shown of similar failure modes and mechanisms.

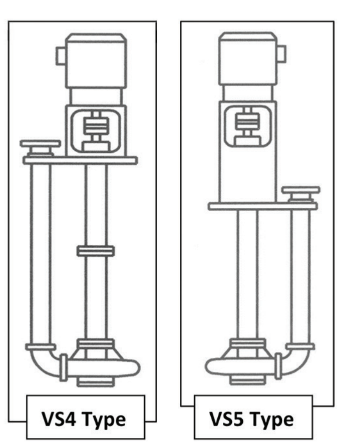

FIG. 1. API vertically suspended VS4 and VS5 pump types.

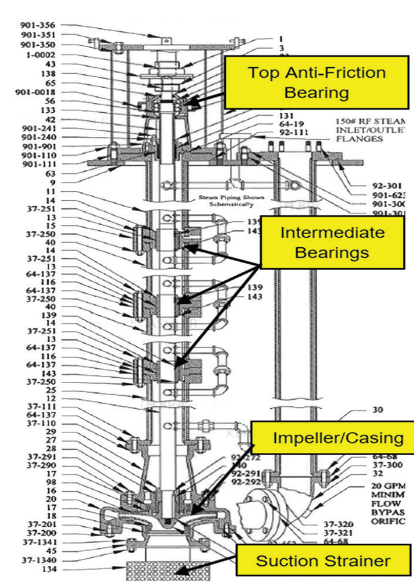

FIG. 2. Cross-sectional API VS4-type pump. Source: Lewis Pumps.

LOSS OF FLOW OR REDUCED CAPACITY

There are many causes for reduced flow or loss of flow conditions, which are typically caused by unfavorable suction conditions. The following outlines various unfavorable suction condition scenarios.

Fouled suction. Most designs—including both dirty and clear sulfur services—utilize a suction strainer. These strainers should be adequately sized in terms of both surface area and perforation size. In addition, stainless steel is recommended to resist corrosion, which can compromise the integrity of the strainer. The important thing is to not assume that the pump will only see clean molten sulfur. Foreign material is a real possibility, depending on the integrity and condition of the sulfur pit. Any deterioration of the sulfur pit that introduces foreign material to the sulfur has a strong possibility of making it to the pump suction boot.

FIG. 4 shows a severely fouled suction strainer, resulting from submergence in a foreign material. In this case, the root cause was not pump related, but rather the failure of the sulfur pit wall (**FIG. 5**). As shown, the acid bricks collapsed, followed by the release of a foam glass material used for insulation behind the bricks. This foam glass and other foreign material continuously collected at the bottom of the pump suction boot area, where it eventually blocked the suction strainer.

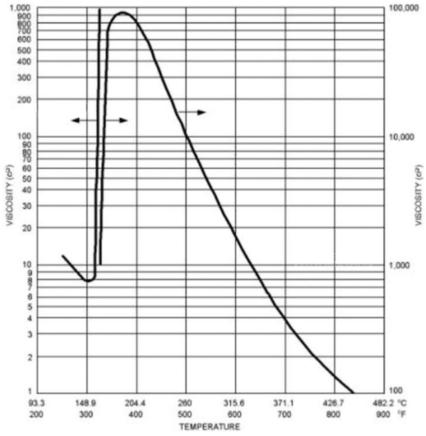

FIG. 3. Sulfur viscosity vs. temperature plot.

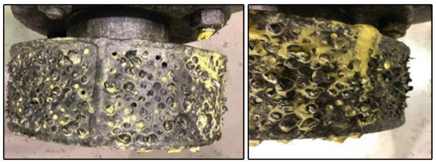

FIG. 4. Fouled suction strainer with foreign debris.

FIG. 5. Bricks collapsed, releasing foam glass.

Viscosity changes and temperature control issues. For proper pumping function, temperature control is critical for maintaining the sulfur within the required temperature range. Any issues with the temperature control of the sulfur pit can quickly turn into pumping problems. Pit temperatures should be frequently monitored for proper temperature control. H_2S content is also a factor to consider regarding the viscosity vs. temperature characteristic.

High viscosity not only affects the pump's ability to deliver flow but can also affect the lubrication to the intermediate bearings, due to low-flow or no-flow conditions. The brake horsepower required also increases and can result in motor overload.

Cavitation/submergence issues. Net positive suction head (NPSH) and submergence issues can also cause loss of flow or low-flow conditions. These conditions often arise from level control issues. These systems are exposed to high temperatures and possible corrosion issues; therefore, these systems should be properly maintained to ensure proper pump operation.

FIG. 6. Unsupported pump discharge piping.

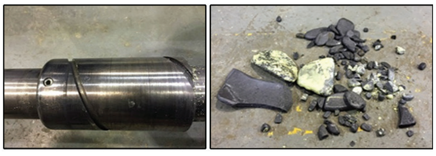

FIG. 7. Overheated line-shaft bearing and broken bushing.

High vibration amplitudes. Due to the inherent design of the vertically suspended pump, the working end of the pump is located several feet below grade and is submerged in the molten sulfur. Seismic vibration data is typically measured at the motor and the pump top bearing locations. This makes it difficult to diagnose issues occurring at the bottom of the pump at the suction inlet and the line-shaft bushings. Typical failure modes related to vibration issues include top pump bearing failures and line-shaft bearing/bushing failures.

The following are typical mechanisms associated with high vibration amplitude:

- Excessive pipe strain
- Driver misalignment
- Lack of line-shaft bearing/bushing lubrication.

Excessive pipe strain. External loads on the pump can cause distortion of the pump, resulting in internal misalignment and bearing failure. Machine misalignment can also result in elevated vibration amplitude and shortened bearing life. **FIG. 6** shows an unloaded discharge piping support, which resulted in external loads on the pump. These external loads, along with other mounting issues, resulted in failure of the top anti-friction bearing, along with high vibration amplitudes.

Driver misalignment and mounting issues. Careful pump mounting, pipe connections and shaft alignment should be executed to minimize any external loads on the pump. Shaft deflection checks should be conducted with two dial indicators in both orthogonal directions (radial) during piping connections to ensure no more than 0.002-in. pump shaft deflection. The pump should be rotated by hand, following piping attachment and warm-up. This action should be done just prior to startup to ensure that the shaft turns freely and that there are no issues with internal misalignment.

Line-shaft bushing lubrication issues. For the VS4-type pump, the line-shaft bearings are lubricated by the sulfur; therefore, any foreign material or abrasives in the sulfur will compromise the bearing/bushing life. In addition, the viscosity of the sulfur can also have a detrimental effect on the product lubricated bushings.

FIG. 7 shows a line-shaft bearing/bushing. The bearing shows evidence of high temperature from lack of lubrication, and the carbon bushing was fractured.

The shaft speed of vertical pumps with sulfur-lubricated sleeve bearings is critical in terms of increased friction/temperature, which can result in damage from sulfur solidification. Low-flow conditions will also add to this temperature rise in the bearings. Based on these factors, it is recommended to restrict shaft speed to a maximum of 1,800 rpm. FIG. 8 shows a couple of cases where shafts have failed due to lubrication issues and high heat generation at the sleeve bearing. This is based on reducing the radial loads/forces and to reduce the risk of temperature increase in the sleeve bearings.

Corrosion issues. Pump material selection is an important design consideration to ensure adequate corrosion resistance. The following case example demonstrates that there can be other corrosion mechanisms to consider, which can have a direct influence on pump reliability. The presence of water and sulfur containing H_2S can result in wet H_2S corrosion in the vapor space, which can lead to deterioration of the sulfur pit.

FIG. 9 shows significant concrete desiccation at the pump soffit location and other areas of the sulfur pit walls. Severe corrosion of the cover plate was also present. These conditions resulted in both corrosion and introduction of foreign material to the pit. It is imperative to mitigate water intrusion from washdown, steam-leak and environmental issues. This corrosion mechanism can also result in corrosion of the pump baseplate and foundation, resulting in reduced stiffness and subsequent vibration and alignment issues.

Takeaways. There are a few takeaways to highlight; however, none of them are more important than the initial design review to ensure that the sulfur properties and other design aspects have been considered. Choosing the right application will be critical to maintain acceptable reliability. The following actions highlight a few of the key considerations to ensure trouble-free operation:

- Ensure proper installation to minimize the external loads on the pump.
- Always perform precommissioning checks prior to startup.
- Ensure that temperature and level controls are working for proper pump function.
- Mitigate any steam leaks or other sources of water to avoid wet H_2S corrosion.
- Conduct sulfur pit inspections periodically to identify any sulfur pit deterioration and subsequent accumulation of foreign material in the pump suction boot area.

The following is a list of proven maintenance and reliability tips for improving molten sulfur pump reliability and reducing maintenance costs:

- Utilize flexible steam hoses to maintain steam to jacketing during pump removal. This will allow for proper draining of the pump, as well as for maintaining temperature on the pump during the free draining of the pump when lifted from the pit. Residual sulfur left in the pump requires significantly more time and effort to perform maintenance and parts can be damaged during disassembly, resulting in higher maintenance costs. It is often difficult to distinguish between damage due to disassembly or from operation during the troubleshooting.
- Before applying steam to the pump jackets and starting the pump, ensure that the pump has reached equilibrium temperature. The pump should be held in the pit for several hours to allow all the parts to reach uniform temperature. If steam is applied prematurely, the pump components will grow at different rates and cause possible damage.
- Operation procedures should include a monthly pump rotation to ensure that foreign material does not accumulate around a long-term standby pump.
- All water sources, including wash water, should be avoided on or around the sulfur pit. Utilize water stops to prevent ingress of water.
- Always baseline the pump performance variables following commissioning, which can be used for future troubleshooting purposes. These key variables include discharge pressure, motor amperage, and top anti-friction bearing housing skin temperature. HP

FIG. 8. Failed line shaft and sleeve bearing location.

FIG. 9. Soffit and cover plate damage due to wet H_2S corrosion.

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How to select the proper valve for reliable performance in critical/severe service applications

Critical and severe service applications demand automated valves that perform reliably under punishing conditions, such as high temperatures, high cycle rates, high shutoff pressures, high velocities, very long required service lives and zero-leakage requirements. These applications may handle poisons, corrosives, slurries, heavy particulates or other very dangerous or difficult-to-handle process media.

Selecting an automated on-off valve that operates reliably under these conditions with these media can be very challenging, especially if the valve is critical to plant operations.

While there are several valve technologies to choose from, a triple offset valve (TOV) is a good choice for many critical and severe service applications (**FIG. 1**), particularly when zero-leakage performance is required.

This article will familiarize the reader with the internal seal design and capabilities of this valve type, and will show why it is a good fit for critical and severe service applications.

Before discussing the valve design in detail, it is important to clarify some misconceptions about leakage rates with metal-seated valves and to define the test requirements used to verify performance.

Zero-leakage shutoff as defined per API 598 and ISO 5208 standards.

Many critical and severe service applications require a bidirectional, zero-leakage shutoff utilizing metal-to-metal seats. This is a very difficult requirement to meet, and the American Petroleum Institute (API) 598 standard does not have a metal-seated specification for zero leakage, only providing a zero-leakage specification for resilient seated valves. To add to this confusion, terms are used throughout the valve industry (e.g., bubble tight, drop tight and leak tight) that technically have no true shutoff rating or definition. In addition, many engineers are under the misconception that Class 4 shutoff is zero leakage. It is not, as Class 4 is a leakage rate standard applied to control valves but not to the shutoff capability of isolation valves.

The International Organization for Standardization (ISO) 5208 standard differs in the way it categorizes valve seat performance standards. ISO 5208 simply qualifies shutoff within a category, rather than the type of seat. For bidirectional, zero-leakage applications, valves should be qualified to ISO 5208 Rate A.

Some vendors state that their valve is "tested to API 598," while failing to mention which test standard within API 598 was used. The API 598 Resilient Seat test standard specifies zero bubbles and zero drops of water during the bidirectional seat leakage test. Valves successfully passing this test standard are considered to have zero leakage. It is this test protocol—API 598 Resilient Seated—that is usually applied to TOVs, even though these valves are metal seated.

There are other test protocols within API 598 for metal-seated valves that have an allowable leakage rate, and the allowable leakage increases significantly with valve size. While these leakage rates may be acceptable for some processes, they are unacceptable for many critical and severe service applications. Processes such as pump isolation, bypass valves, headers, emergency block valves and reactor isolation valves will all place pressure on valves from either direction, so a bidirectional, zero-leakage seal is a clear requirement.

Understanding triple offset technology.

TOVs employ three offsets in their design (**FIG. 2**). The goal of the design is to have the valve disc seal meet the mating body seat with no rubbing until the components meet and touch simultaneously over the entire 360° of the seat and seal. This is accomplished by offsetting the shaft upstream of the seating surface and moving the shaft slightly to one side of the centerline of the pipe. These first two offsets eliminate any rubbing during most of the valve travel, and the third offset ensures performance over the remaining valve travel.

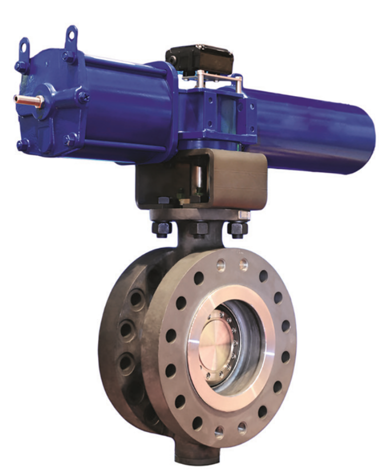

FIG. 1. A TOV is often the best choice for critical and severe service applications requiring zero leakage.

The third offset consists of a seat-and-seal geometry that resembles an inclined cone. The inclined bevel of the disc seal and the integral body seat form a very tight junction along the entire sealing surface as the valve reaches the closed end-of-travel position. This inclined cone geometry is a critical design component because it eliminates any rubbing between the seat and seal.

As the valve closes, the seat and seal contact simultaneously around the entire circumference of the valve, and then torque is applied to the shaft to fully seat the disc seal. This provides a bidirectional, zero-leakage seal, independent of line pressure. Quality valve manufacturers can achieve bidirectional, zero-leakage seals with both laminated and solid disc seals.

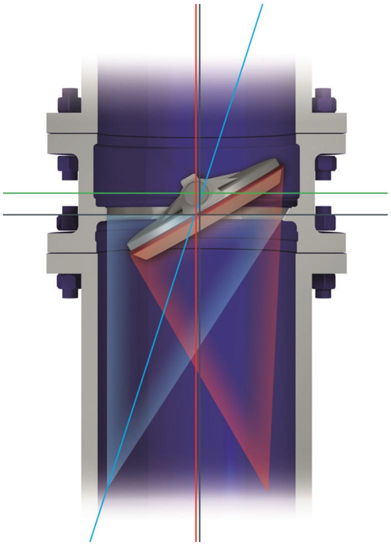

FIG. 2. The TOV design employs three offsets to make the entire disc and body sealing surfaces touch at the same time as the valve closes.

Some TOV manufacturers claim to have a fourth, and even a fifth, offset in their designs. Considering that high-quality TOVs are completely non-rubbing and have bidirectional, zero-leakage seals, providing additional offsets is not necessary and may even detract from the valves' performance.

The TOV design achieves bidirectional, zero-leakage performance utilizing metal-to-metal seats. It is also fire safe and rated up to Safety Integrity Level 3 (SIL-3) for use in critical areas where safety instrumented systems are often applied. Additionally, these valves are temperature rated up to 815.6°C (1,500°F) and offer alternate designs for cryogenic service—utilizing quarter-turn actuation to minimize fugitive emissions from the stem packing, while providing greater reliability and ease of maintenance.

Fugitive emissions. Fugitive emissions have become a major concern for operators. With consent decrees and environmental awareness on the rise, a valve's stem seal performance should be taken into consideration, as it directly affects leak detection and repair programs. There are many facets within the scope of fugitive emissions.

API 622 and API 624 address the packing material and packing gland efficiency, respectively. EPA Method 21, TA Luft and ISO 15848-1 standards provide acceptable emission levels and testing criteria for the evaluation of the efficacy of the valve packing gland. While the rates of leakage and the material selection for the packing are paramount to selecting a valve, most manufacturers adhere to the limits set forth by these standards.

For the purposes of this article, the focus will be on the type of packing gland, specifically rising stem vs. quarter-turn operation of the automated isolation valve. With respect to critical and severe service applications, the use of rising-stem gate valves and rising-stem ball valves have been the standard for years.

These rising-stem isolation valves can be replaced with a quarter-turn TOV with live-loaded packing to reduce fugitive emissions and maintenance expenses significantly, while increasing uptime. With rising-stem valves, the stem is pushed/pulled through the packing. Any foreign particles or changes in stem diameter due to temperature gradients will lead to a stem seal leaking at an unacceptable rate—requiring repair or replacement at significant expense, along with a possible interruption in production.

A quarter-turn valve with live-loaded packing is a more effective solution for fugitive emissions control. The area of the shaft in the packing gland rotates in a quarter-turn motion, so that the shaft in that area is protected from external and internal disruption. The live-loaded nature of the packing gland automatically adjusts to minor changes due to normal wear and temperature changes.

This live loading is accomplished via Bellville washers, which are concave washers arranged in pairs, with the opposing concave surfaces facing inward upon themselves. These washers are completely compressed by the gland nuts, effectively providing a compact spring-loaded gland packing.

While these points provide a base of knowledge to draw upon, there are areas that may require consultation with a valve vendor or manufacturer for a more detailed analysis and for recommendations for particular applications.

Valve selection for specific applications. The following examples discuss several difficult applications and provide suggestions for addressing them.

Sulfur recovery units pose extreme challenges for automated valves. Solidi-

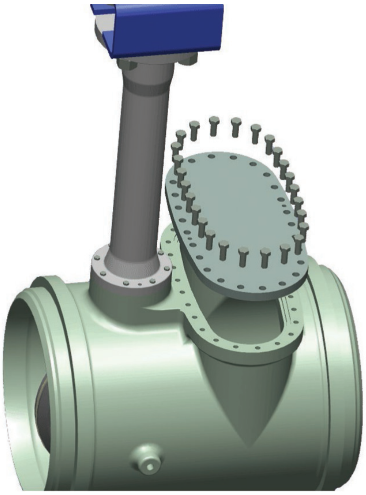

FIG. 3. The diagram on the left depicts a true top-entry design, where all internal parts can be safely, quickly and easily removed for maintenance or inspection. The diagram on the right shows a pseudo top-entry design that makes maintenance and inspection unsafe and time consuming.

fication of sulfur on the valve internals causes components to stick and restrict valve travel—and process upsets create significant corrosion problems. In this application, a steam-jacketed TOV that is compliant with National Association of Corrosion Engineers (NACE) standards works well. The constant application of heat across the valve body keeps the sulfur well above its melting point, thus avoiding sticking and sealing problems caused by solidified sulfur. The metal seal ring and Stellite 21 body seat combination are robust enough to handle the difficult media.

Cryogenic LNG applications push valve materials to the limits of their capability, with processes within these plants and facilities operating at very high pressures and extremely low temperatures. TOVs work well in this application because they can handle extreme temperature gradients, while still providing a firesafe valve with the required shutoff capability.

In addition, some butt-weld LNG applications require top entry, which is available in a TOV design, but not all butt-weld top-entry valves are created equal. The left diagram of **FIG. 3** illustrates a true butt-weld top-entry design, where the entirety of the valve internals can be safely and efficiently removed for safe and fast access and/or repair.

Some valve manufacturers employ an access port on the top, as shown in the right diagram of **FIG. 3,** or on the side of the valve body. These entry ports are only effective as an access point and cannot be used for safe and effective repair work.

Takeaway. When faced with the task of selecting a valve for critical or severe service, it is important to carefully evaluate the options, and to choose the valve that provides the best performance and lowest lifecycle cost. While lower cost options may be available, the added cost of constant valve repair and replacement, combined with lost-production costs or efficiencies associated with poor sealing performance, will far outweigh any initial savings in most applications. Consultations with experts can help quantify these costs and justify purchasing the right valve for the application.

For critical or severe service, TOVs are often the best choice for automated valve applications, as they generally cost less and weigh less than other valve options offering similar performance. When carefully specified, TOVs provide reliable bidirectional, zero-leakage performance.

The best valve choice is often dictated by the process or application. When questions arise regarding selection, valve vendors can provide assistance and consultation to ensure best selection. HP

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